PSERC

Facilitating Environmental Initiatives While Maintaining Efficient Markets and Electric System Reliability

Final Project Report

Power Systems Engineering Research Center

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Facilitating Environmental Initiatives While Maintaining Efficient Markets and Electric System Reliability

Final Project Report

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Power Systems Engineering Research Center

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Executive Summary

Emerging environmental policies to reduce CO_2 emissions will raise a number of challenges for the electric power industry as it continues to maintain a reasonably priced and reliable supply of electricity. For instance, the industry faces the likelihood of:

- increased generation from numerous and diverse new energy sources that emit less CO_2 (if any) than traditional alternatives
- ever more restrictive caps on CO_2 emissions from all generation sources
- increased loads from plug-in hybrids and other forms of energy storage
- wide-ranging demand response programs using smart grid technologies.

Besides policies for reducing CO_2 emissions, there is the possibility of tighter standards on NO_x and SO_2 emissions to reduce ozone and fine particulates.

Careful analysis of the implications of those environmental policies is warranted because of the effects they could have on retail prices, on the system-wide cost of operation, on reliability, and on emissions of all pollutants. Our study focused on a particular environmental policy: cap-and-trade.

Analysis of a Cap-And-Trade Program Using an Economic/Engineering Model

A cap-and-trade program operates by capping the total amount of emissions, distributing emission allowances, and then establishing a market with a price of each tonne of emissions rights purchased or sold in a permit market. Under the program, a firm that expects to exceed the amount of emissions that it is allowed based on the number of allowances it owns can either

- incur the cost of reducing its emissions (such as through emissions redispatch or investment in technologies that reduce emissions), or
- incur the cost of purchasing emission permits (or the right to emit) in an emissions permit market.

Firms are expected to make the decision between those two strategies so that they can minimize their costs and thereby maximize their profit.

A cap-and-trade program, like an emissions tax (where a tax is placed on each tonne of emissions), puts a price or market value on each tonne of emissions. Examining the response of the power industry to a price on emissions allows us to predict the effect of a cap-and-trade program as well as an emission tax program. We use the term “emission price” to refer generically to either the permit price in a cap-and-trade program or the emission tax rate.

We used an economic/engineering model of the power system in the northeastern United States as the conceptual framework for analyzing the impact of environmental regulation of CO_2. In our study, we conducted simulations using a 2007 power system with network reduction to capture both power flows and voltage constraints, thereby enabling "stress testing" of the current power system. The study examined:

- the effectiveness of the Regional Greenhouse Gas Initiative (RGGI) in the ten northeastern states that have begun cap and trade for CO_2
- the impact of prolonged drought on the price of CO_2 emission allowances in RGGI
- effects of current and proposed CO_2 regulation on electricity prices
- allowance prices and emissions of CO_2, NO_x, and SO_2, as well as industry costs
- the impact of proposed national legislation for a cap-and-trade program for CO_2, including the long-run demand response for electricity.

Conclusions

Our analyses led to a number of conclusions about the effects of cap-and-trade policy on the electric power industry.

- ***The short-run demand for CO_2 emission allowances in the electric power sector is likely to be extremely insensitive to carbon price changes (that is, extremely inelastic).***

We ran simulations of the northeast power system with a cap-and-trade policy applied through region. In the simulations, raising the carbon dioxide emission price to $50 from $0 reduced demand for CO_2 allowances by only 2%. A $100 price reduced total emission allowance demand by only 6%. This extreme insensitivity of emissions to carbon price changes suggests that a poorly designed cap-and-trade program could do major harm to the industry and the economy because prices in the allowance permit market could become very volatile and could escalate dramatically in response to a shortage of permits. A shortage of permits could be experienced in a period of high consumer use of electric energy. This price escalation could result in dramatically higher prices for consumers under a real-time pricing regime currently envisioned as an appropriate pricing policy with a smart grid or dramatic declines in industry profitability if retail prices are capped.

- ***Leakage may be a major issue for regional cap-and-trade programs***

Leakage is the tendency to shift power production from emissions regulated generators that have to buy CO_2 permits to unregulated generators that do not have to buy CO_2 permits and have lower production costs. Leakage makes a cap-and-trade program less effective in reducing emissions. This is true both for the Regional Greenhouse Gas Initiative (RGGI) and for the proposed U.S. national CO_2 cap-and-trade program (assuming the U.S. and Canada differ in stringency). With leakage, more power will be imported from outside the regulated region after the cap-and-trade regulation is imposed when the cost of doing so is less than the cost of power plants operating under CO_2 emission allowances within the regulated region (or country). Our analyses of leakage led to the following findings:

  - Leakage dramatically raises the system-wide costs of reducing CO_2 emissions in comparison to the case where all generators face emissions regulation.

- o If generators of less than 25 MW capacity are exempted from emissions regulation, as is done in RGGI, the cost of reducing CO_2 emissions increases dramatically because of within-region leakage to those unregulated generators.

AC and DC simulation runs generally produced similar results regarding the potential for leakage. This implies that future studies may be able to employ the more simple approximate DC approach to modeling large networks.

- ***A prolonged drought in the Northeast could severely impact CO_2 permit prices in RGGI***

Hydroelectric generation has low cost and zero emissions. If that generation is unavailable, not only are operating costs higher, but there is more pressure on CO_2 permit prices as emissions from non-hydroelectric facilities are forced to increase. The price increase would be buffered substantially in a national program.

- ***CO_2 permit prices have a large impact on other emissions and the demand for permits for SO_2 and NO_x.***

CO_2, NO_x and SO_2 emissions are physically linked by the generation technologies. Policies that change CO_2 emissions effect other emissions as well. Since NO_x and SO_2 emissions are also of concern, the effect of cap-and-trade on all emissions needs to be analyzed. We found that the interactions can be substantial.

Implications of Findings for a National Cap-and-Trade Program

Although the northeastern power system is not representative of the national system, a number of observations about a potential national cap-and-trade program are suggested by our findings .

- ***Demand reduction has significant potential for reducing CO_2 emissions from the electric power industry***. The current electric power system cannot produce significant reductions in CO_2 emissions in the Northeast at acceptable electricity prices in the short run because of inelastic demand for electricity. However, the long-run demand elasticity of -1 for electricity implies that a 10% increase in prices will cause a 10% decrease in demand, mostly through energy conservation. In contrast to the short run situation, the long-run electricity demand response associated with the proposed cap-and-trade program of the Waxman-Markey bill is likely to dramatically limit price increases, even with the existing power system left in place. This implies that, in the long run, with additional investment in generation, transmission, and energy conservation, electricity prices will rise, but only slowly.
- ***Cap and trade can produce extreme allowance price volatility and uncertainty for multiple pollutants***. Generators would likely prefer the certainty of emissions taxes for investment planning. However, it is possible that the emission price floor (such as proposed in the 2009 the Waxman-Markey bill where CO_2 permits are proposed to sell at auction for a minimum of $10 in 2012 rising at 5% per year in real dollars) will set the market price when the actual emissions are lower than the emissions cap. In this case, (based in part on a long-run demand response), the CO_2 regulation would act more like a emissions tax and provide predictable incentives for new generation and planning.

Future Research Needs

This research suggests two critical research needs. First, based on the strong interaction effects between the demand for CO_2, NO_x, and SO_2 permits, as well as the difficulty in modeling the de-commitment of generators at high permit prices, a robust planning tool is needed that (1) can solve the unit commitment problem by simultaneous optimizing over many sequential OPFs, (2) can also incorporate the spatial aspects of environmental modeling to predict ambient pollution for fine particulates and ozone, (3) can optimize investment, and (4) can handle short and long-run demand response, realistic networks and contingencies.

Second, given the likelihood of national pollution permit markets for CO_2, a detailed national model is needed that correctly models network flows to explore the national issues raised in our study on the Northeastern power system.

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1. Introduction

The characteristics of an electric power network can strongly influence the effects of environmental policies that are applied to the power sector, because the constraints and flow characteristics of the network determine the extent to which power from lower-emitting power plants can substitute for power from higher-emitting plants in other locations. However, realistic modeling of power networks is challenging. Actual power networks are "alternating-current" networks. Thousands of constraints on flow, voltage, stability, and power production govern the operation of such a network. Many of these constraints are non-linear and complex. Furthermore, the flows in such a network do not just follow the shortest or most under-utilized route from where power is generated to where it is consumed, but instead flow along all connected lines, including ones that may already be congested, in accordance with laws of physics known as Kirchoff's Laws. Because of the complexity of creating and solving a realistic power system model, simpler models have been used instead. These include "direct-current approximations" and "regional-flow-constraint" models. We describe these simpler models in Section 3.

We use an alternating-current model of the power network in northeastern North America to predict the effects of several different incentive-based carbon dioxide regulations. We use all of the kinds of flow equations and constraints that govern the actual system. To our knowledge, this report is the first to analyze an environmental policy using an alternating-current model of a power network. This report makes three contributions to the environmental and energy economics literature. The first is to demonstrate and further develop the use of alternating-current modeling. The second is to compare the predictions of an alternating-current model with those of a direct-current approximation of the same model and with an unlimited-transmission model of the same region. This comparison is a test of whether our more complex modeling is warranted. The third contribution is to predict the effects of different incentive-based carbon dioxide emission regulations on emissions and total variable cost. Among other scenarios, we simulate a U.S.-only regulation, a Canada-only regulation, the Regional Greenhouse Gas Initiative[1] ("RGGI") in the presence of a drought, the effects of exempting smaller generators from a carbon dioxide regulation (as done in RGGI), and the interaction of incentive-based carbon dioxide and sulfur dioxide regulations. We have not previously seen any of these examined in the literature. In addition, we consider the impact of long-run demand response that can mitigate the impact of regulation by reducing demand for electricity.

Around the world, there is the potential for one region to adopt an incentive-based carbon dioxide emission regulation without a neighboring region doing so, or for one region to have a more stringent regulation than the neighboring region does. Our simulations of U.S.-only, Canada-only, and RGGI-only regulations examine such situations. A network model is particularly important in simulating such situations because the network determines the amount of emissions "leakage" that can occur. Leakage refers to the increased emissions at generators outside of the regulated region as a result of the increased marginal operating cost for generators inside the regulated region. Leakage can partially or completely offset the emission reductions that result from the regulation.

[1] The Regional Greenhouse Gas Initiative is a cap-and-trade program in ten northeastern U.S. states.

As mentioned above, we also simulate the RGGI policy in the presence of a drought. Our purpose in doing so is to examine the potential for permit price volatility under a cap and trade program. A drought reduces hydropower, therefore increasing the need for carbon dioxide-emitting generation and the price of emission permits.

Both an emission tax and a cap-and-trade program operate by creating a price or opportunity cost that each firm incurs for each ton of emissions. As a result, examining the response of the power industry to a price on emissions allows us to predict the effect of both emission taxes and cap-and-trade programs. We will use the term “emission price” to refer generically to either the permit price in a cap-and-trade program or the emission tax rate.

This report is organized as follows: The second section reviews current and proposed legislation at the national and regional level for regulation of CO_2. The third section presents the optimization/simulation model and network used in the analysis and contrasts this work with existing work. The fourth section presents results from the simulation model that allows analysis of the effects of various CO_2 prices either from a cap and trade program or a carbon tax on emissions and total variable cost. The fifth section introduces long-run demand response and simulates the impact of the proposed national legislation (described below) on the power system in the Northeastern United States.

2. Current and Proposed Legislation

This section will first describe the currently proposed U.S. national CO_2 mitigation legislation, the American Clean Energy and Security Act of 2009 (ACESA) introduced by Henry Waxman and Edward Markey. Then, the various regional initiatives will be identified and one, the Regional Greenhouse Gas Initiative (RGGI), will be described in detail since it forms the basis for part of our case study that is able to contrast regional to national policies.

The ACESA proposes the following greenhouse gas (GHG) reductions over time:

- By 2012: reduce to 1% below 2005 levels
- By 2020, reduce to 17% below 2005 levels
- By 2030, reduce to 36% below 2005 levels
- By 2040, reduce to 55% below 2005 levels
- By 2050, reduce to 73% below 2005 levels

These are the reductions that are proposed through separate cap and trade programs for CO_2 and hydrofluorcarbon (HFC). The quarterly auctions are proposed to start in March of 2011 for 2011 allowances and the use of offsets (credits earned from emission reduction activities, such as tree planting or reducing emissions from a facility in another country) is limited to a specified percentage each year determined by formula. For example, in 2013 not more than 15% can come from domestic offsets and not more than 15% can come from international offsets. Banking of allowances is unlimited and next year's allowances can be utilized in the current year without interest. Up to 15% of needed allowances can be borrowed from following years up to five years but 8% interest per year must be paid in the form of purchase of additional allowances.

The ACESA would initially distribute 84% of the permits free of charge in the first year allocating permits as follows:

- **60.5% to Consumer Protection** (35% to local electricity distribution companies, merchant coal, and long term power agreements, 15% for low and moderate income households, and the remainder to offset price increases in heating oil and natural gas);
- **14% to Energy Efficiency and Clean Energy** (10% to States, 3% to advanced automobiles, and 1% to research and development);
- **9.5% to Other Public Purposes** (5% for preventing tropical deforestation, 4% for domestic and international adaptation and technology transfer, and .5% for worker assistance and job training).

The permits allocated to many of these areas phase out over five to ten years starting in 2026, but the allocations to some areas increase and some new areas are added over time. Finally, the bill temporarily (until 2017) prohibits States from running their own cap and trade programs but those holding allowances from the Regional Greenhouse Gas Initiative or California (see below for a discussion of these regional programs) would be compensated with allowances from the proposed Federal program. Figure 1 shows the greenhouse gas targets of the ACESA.

In addition to this proposed federal legislation, three regional cap and trade initiatives are underway as shown in Figure 2. Note that these three initiatives comprise 37 percent of U.S. emissions. The states in RGGI contain 16% of the U.S. population (Grenfell, 2008) but emit only 10% of U.S. GHG emissions, in part because of the RGGI region's electricity generation mix that uses relatively more natural gas and less coal than some other areas.

In this study we focus on the Regional Greenhouse Gas Initiative because of the availability of an existing network model that can explore many issues that have been raised concerning CO_2 regulation. RGGI has ten member states shown in Figure 3, importantly excluding Pennsylvania that has a substantial availability of coal fired generation. RGGI plans to reduce power-sector CO_2 emissions 10% from the 2009 level, between 2009 and 2018. Note that it is significantly less stringent than the ACESA.

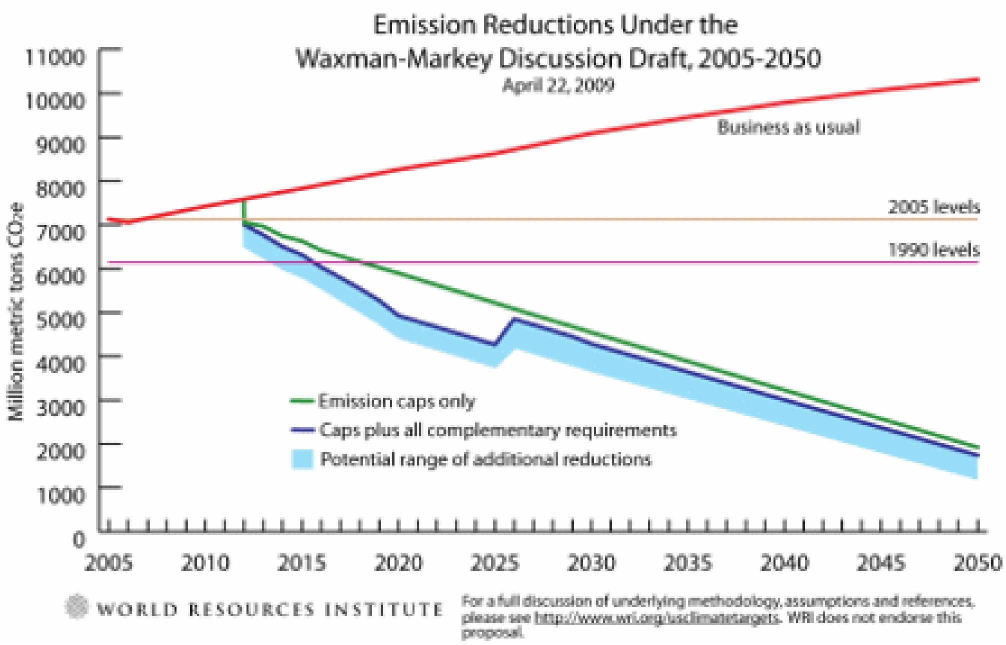
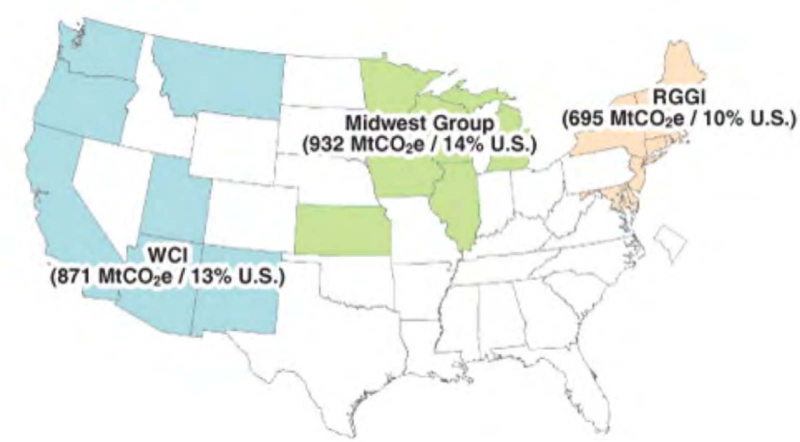


Figure 1: The American Clean Energy and Security Act of 2009 Emission Targets.

Source: Larsen and Heilmayr April 22, 2009.



RGGI = 10% of U.S. total GHG emissions
MW = 14%
West = 13%
TOTAL: 37%

Figure 2: Total GHG Emissions of States Participating in Prospective Regional GHG Cap and Trade Initiatives

Source: Damassa, 2007. Notes from source: "GHG emission totals from Canadian Provinces participating in the Midwest Accord and WCI are not included here. $MtCO_2e$ is million metric tons of carbon dioxide equivalent per year. Percentages are of total U.S. emissions."

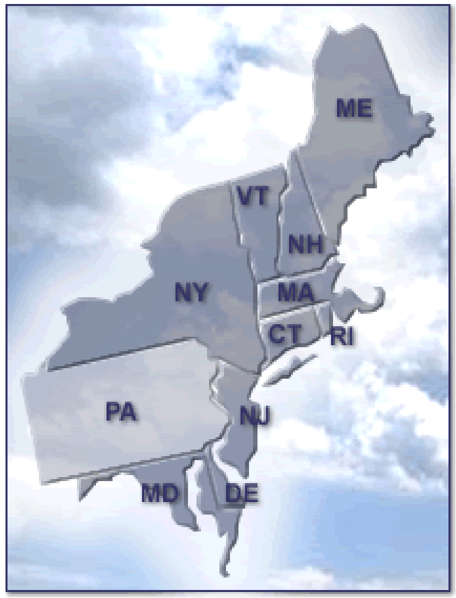


Figure 3: Member States of the Regional Greenhouse Gas Initiative.

Source: http://www.awm.delaware.gov/Info/Regs/Pages/RGGI.aspx. Accessed July 26, 2008.

In the 2009–2014 interval, emissions will be capped at 2009 levels. From 2015–2019 the cap is reduced by 2.5% per year. Currently, 6 states plan to auction off 100% of their permits. The others are required to auction at least 25% of permits. Auction revenue will be used for consumer benefits including energy efficiency programs. A three-year compliance or "true up" period will be enforced unless the trigger price of $10 is reached in which case this period can be extended. Offset usage is limited to 3.3% unless the trigger price reached, so that, if permits reach $10/ton, there will be no limit on offset use. The first three quarterly auctions yielded prices per ton of $3.07 (9/25/2008), $3.38 (12/17/2008), and $3.51 (3/18/2009) for 2009 allowances. All of the allowances offered so far have been sold.

As noted above, one of the main worries for regional programs is "leakage." As generators inside regulated areas are forced to pay for carbon dioxide (CO_2) permits, the prices at which they can offer to profitably sell power rise compared to the prices at which generators outside of the regulated region can offer to profitably sell power. This may cause emissions to increase outside of the regulated region, partially offsetting the emission reduction inside the regulated region. In what follows, we measure leakage in our simulations of RGGI, U.S.-only, and Canada-only policies. We also demonstrate what happens if all of the Northeastern states and provinces are regulated in a "bi-national" program. A bi-national program is also akin to a national program in which leakage is prevented or is small. There is no model of the whole United States that has been aggregated or "reduced" to make it solvable in AC simulations, so we are limited to AC modeling of a U.S. or Canadian national policy in the Northeastern United States. However, this should provide some insights into the implications of a uniform bi-national policy.

3. The Simulation Model and Network

Several studies of CO_2 regulation have been conducted to examine the issue of leakage. First, the ICF (2007) IPM model has been used to examine the leakage issue for RGGI. This is a national model that includes very detailed data on every generator in the United States as well as emission rates for various pollutants including CO_2. However, it assumes that transmission is unconstrained within regions and constrained by aggregate flow limits between adjacent regions. Thus, it is not a model of even simplified DC flows, but assumes that electricity flows as if through "pipes." This makes the model easier to solve. Similarly, the Resources for the Future Haiku model (Paul and Burtraw, 2002) uses constraints between regions and models generation using hundreds of characteristic "typical" plants including typical emission characteristics. Both of these studies suggest that leakage occurs but is not so great as to defeat CO_2 emission reductions by RGGI. The two models differ in how they treat fuel prices, investment, retirement of plants, etc. These comments should not be taken as critical of these models. Rather, the type of detailed network modeling we are attempting is quite difficult and, simply put, might not be important enough to justify the effort required. One of our goals is to test the hypothesis that it is important to model the network with the added realism of alternating-current constraints and flow equations.

The reason we focus on this issue is that, around the world, electric power systems or “grids” are predominantly alternating-current systems. As noted in the introduction, a complex set of constraints and flow equations governs each such system. One of the most important sets of constraints is voltage constraints: voltage must be maintained within acceptable limits and more expensive plants must often be operated in order to achieve this. Furthermore, rather than flowing on the shortest or least congested path from source to point of use, power flows along multiple lines, potentially including already-congested lines, in accordance with Kirchoff’s Law. The resulting constraints and flow equations affect which set of generation units satisfies electricity demand at the lowest cost in each moment. Consequently, these constraints and flow equations also play a major role in determining the effects of a carbon-dioxide emission regulation on emissions, cost, prices, fuel use, and leakage.

The reason for using a more realistic model of the transmission system is well illustrated by the California experience where markets were designed and introduced on the assumption that transmission constraints were relatively unimportant. In fact, transmission constraints proved fatal to that market design, making the market much less competitive than economists initially assumed. Another example is the Northeast power outage that occurred in August of 2003. Markets in Ohio (unlike the rest of the Northeast) were not designed to provide incentives for generators to assist in maintaining voltage (a public good). This design flaw, which resulted from a failure to consider the requirements of an AC network, proved to be a major factor in the collapse of the system. Simply put, in a contest between physics and economics, physics wins.

A common simplified method of modeling a power system is to model it as if it were a direct-current system. GE MAPS and PowerWorld are two software packages that use direct-current approximations to model alternating-current power systems. Direct-current models use linear approximations of the non-linear flow equations in an alternating-current system. Direct current systems do not have voltage constraints and do not have the same kinds of stability constraints that alternating-current systems do, so such constraints are sometimes roughly represented by simple flow constraints known as “proxy limits” on transmission lines. These linear approximations and proxy limits are designed to approximate the characteristics of the system under a particular pattern of operation. The more a system departs from that pattern of operation, the less accurate these linear approximations and proxy limits are. Incentive-based emission regulations change the pattern of operation of a power system by making high-emitting power plants more expensive to operate. So, for example, more stringent emission regulations are likely to result in less use of coal-burning power plants and more use of gas-burning power plants. Coal-burning and gas-burning power plants have different geographic distributions, so more stringent environmental regulations may drastically alter the pattern of operation of the power system.

A second deficiency of direct-current modeling of alternating-current power networks is that the transmission prices and locational marginal power prices derived from DC optimal power flows are incorrect and may lead to sub-optimal decisions if those prices are used as incentives or signals for generation or transmission investment.

In this study, MATPOWER, a full AC optimization/simulation framework developed at Cornell University, is used to study the Northeast power system’s response to CO_2 regulation. Like an electricity system operator, MATPOWER minimizes the cost of operating the electric power system subject to the demands and availability of electricity at each node, the transmission capability of the lines in the system, and voltage and stability requirements. Costs of purchasing carbon permits or carbon taxes are incorporated in the optimization. The simulation works by using representative hours and solving the optimization with different CO_2 emission prices. The current study incorporates reliability by requiring that a reserve of extra generation is maintained in each region, so it does not include transmission line outages or other “contingencies” and the only generation units it includes are those expected in 2006 to be operational in summer 2008.

Figure 4 shows the mathematical formulation of MATPOWER. In that formulation, the optimization variables are labeled *x*. The *x* variables are the optimal power flow variables, consisting of the voltage angles θ and voltage magnitudes V at each “bus” or node in the network, and real and reactive generator injections P_{gi} and Q_{gi} at generators i = 1,2,3,…. The objective is to minimize the sum of the generation unit real and reactive power production costs f_{1i} and f_{2i} for i = 1,2,3,… P_g and Q_g are the vectors of the aggregate real and reactive power injections from generators at each bus. P_d and Q_d are real and reactive power consumed by customers, which are exogenous to our model. P and Q are net real and reactive power outflows at each bus. The first two constraints say that, at each bus, power production minus consumption equals net power outflow at all times. S_f and S_t are vectors of the “apparent power flow” (quadrature sum of real and reactive power) on each transmission line. S_{max} is the maximum flow a line can accept without sagging to a level at which vegetation or the ground can cause an arc and power failure. The general linear constraints include “branch angle difference limits,” which we will not describe here. The voltage limits require that voltage remain in a narrow range that will not damage equipment. The generation limits require that each generator be producing amounts of real and reactive power that it is capable of producing. Simultaneously satisfying all of these constraints requires constant monitoring and frequent adjustments by the system operator.

The optimization problem can be expressed as follows:

$$\min_{x,y,z} \sum_i \left(f_{1i}(P_{gi}) + f_{2i}(Q_{gi}) \right) + \frac{1}{2} w^T H w + C_w^T w$$

subject to

$g_P(x) = P(\theta, V) - P_g + P_d = 0$	(active power balance equations)
$g_Q(x) = Q(\theta, V) - Q_g + Q_d = 0$	(reactive power balance equations)
$g_{S_f}(x) = \left\|S_f(\theta, V)\right\| - S_{\max} \le 0$	(apparent power flow limit of lines, *from* end)
$g_{S_t}(x) = \left\|S_t(\theta, V)\right\| - S_{\max} \le 0$	(apparent power flow limit of lines, *to* end)
$l \le A \begin{bmatrix} x \\ z \end{bmatrix} \le u$	(general linear constraints)
$x_{\min} \le x < x_{\max}$	(voltage and generation variable limits)
$z_{\min} \le z \le z_{\max}$	(limits on user defined variables)

Figure 4: The Formulation of MATPOWER
Source: Zimmerman and Murillo-Sanchez, 2007

We do this for the 2007 power system since complete data are readily available to allow stress testing what is essentially the existing system. Investment in new generation and transmission capacity is a slow process, so it is worthwhile to examine what the existing possibilities are for CO_2 reduction in response to emission taxes or cap-and-trade programs.

The optimization problem associated with determining the operation of an AC network has more constraints than a DC system and is non-linear and complex. Consequently, using a simplified representation of the AC network, with dozens instead of thousands of buses, is necessary because it allows us to solve for the operation of the system.

The transmission lines and nodes or "buses" of the physical network representation utilized in the study are shown in Figure 5. The network includes only PJM-East (New Jersey, Delaware, Washington DC, and most of Pennsylvania and Maryland), New York, New England, Ontario, Quebec, and the Maritime Provinces. Allen, Lang, and Ilic (2008) developed this network representation as a simplified version of the northeast power grid, which has thousands of buses. Their simplified representation aggregates the thousands of actual buses in the Northeast into 36 buses, and specifies the electrical characteristics of those 36 buses and the aggregated lines that connect them. The simplified network approximates thermal, voltage, and reactive power constraints of the real system and "…some of the major intra- and inter-area congestion patterns are preserved…." Ilic (2008) has reported that in comparisons between the simplified model and a detailed model of the same region, the simplified model produces results very similar to those of the detailed model. Given that no completed study of CO_2 regulation includes an AC network, it is at least reasonable to examine the issues raised by CO_2 regulation using an available AC network model.

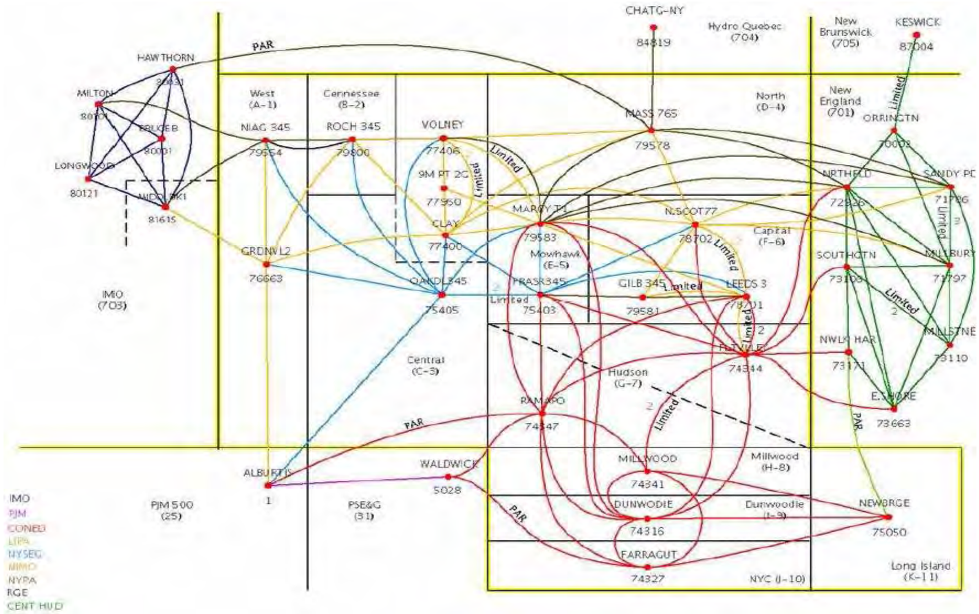


Figure 5: Physical Network Used in Our Simulation.
Source: Allen, Lang, and Ilic 2008.

Our geographic representation of RGGI is approximate. One of the buses in the Allen, Lang, and Ilic model is enormous, and includes parts of states participating in RGGI as well as parts of states not participating. The RGGI states included in this bus are all of Delaware and parts of New Jersey and Maryland. We count this bus as being entirely outside of RGGI, in order to maintain transmission constraints between RGGI and non-RGGI parts of the system.

Our data on generation units, provided by Energy Visuals, Inc, came from the 2006 reliability planning process of the Multiregional Modeling Working Group, the group responsible for examining the adequacy of the electric power system in the Eastern United States and Canada under the auspices of the North American Electric Reliability Council. The data consists of the units projected to be operational in the summer of 2008. There were approximately 2000 such units in the region we model. For each unit, we have name, maximum and minimum real and reactive capability, fuel type, fuel use per megawatt-hour (MWh) of output, fuel price in 2007, longitude, and latitude. From the fuel type, fuel use per MWh, and carbon content of different fuel types (Energy Information Administration, 2009) we calculated the marginal cost per MWh and CO_2 emission rate per MWh of each generation unit. We knew to which of the 36 buses Allen, Lang, and Ilic (2008) had assigned some of the generation units. We assigned the others by geographic proximity and then scaled their real and reactive power capabilities so that our totals at each bus matched that of Allen, Lang, and Ilic. We assume that the units offer all of their capacity at constant marginal cost.

To estimate the outcomes under each policy option during the course of a year, we simulate the outcomes during sixteen representative hours and then average them. The outcomes depend on the amount of power production by each generator in the system. In all three of the power-system models we compare, the power production by each generator is a control variable in a cost-minimization problem that determines the operation of the system. In this problem, the objective is to minimize the cost of operating the system, where that cost includes the price of carbon dioxide emissions.

Table A4 presents the amount of electricity demanded ("load") by region in each hour type, as a proportion of the load in Allen, Lang, and Ilic's model of load during the summer peak hour. Load is highest during the hour that represents the highest-load hours of the summer and is lowest during the hour that represents the lowest-load hours of the fall. Load is assumed to be perfectly inelastic, since few electricity customers face real-time electricity prices. In reality, the quantity demanded is slightly responsive to price in the short term and is more responsive in the long term. This would increase emission reductions from carbon dioxide prices, compared with what we predict below. The higher the carbon dioxide price, the higher the price of electricity, and the higher the price of electricity, the lower would be the quantity of electricity demanded.

Generation units are sometimes not available for operation because of maintenance or repair. Rather than simulate discrete outages, we derate the maximum and minimum real and reactive capability of each unit using an availability rate. Availability is highest in summer and winter because regulators require generators to conduct maintenance during the relatively low-load seasons of spring and fall. Tables A1 and A2 in the appendix show these availability rates, by hour type and fuel type.

The CO_2 prices we consider are \$0, \$3.51, \$25, \$50, \$100, \$175, and \$250 per metric tonne. The \$175 and \$250 prices are much higher than the prices we expect to see under at least one of the policies we model, the RGGI policy. However, the use of these high emission prices enables us to plot the demand curve of emission permits over a wide range of permit prices.

4. Simulation Results

4.1 Two snapshot of the effect of transmission system modeling

Figure 6 shows carbon dioxide emissions as a function of carbon dioxide price imposed on the entire Northeast including the parts of Canada we model, predicted using three methods: our alternating current (AC) model, our direct current (DC) linear approximation of that AC model, and a model with no transmission constraints at all. [2] It shows that in some instances results can be quite similar with these three models. An increasing carbon dioxide price tends to cause a shift from coal-fired generation units to gas-fired units, which tend to be located closer to customers. Therefore, if the carbon dioxide price is imposed throughout the entire region, the change in the operation of the power system that results from the CO_2 price may not substantially exacerbate transmission constraints.

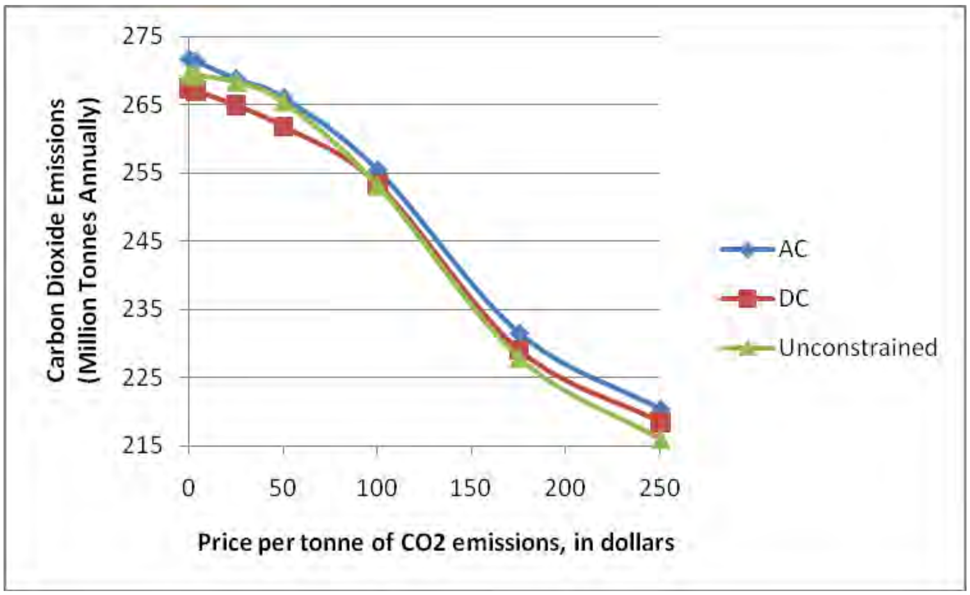


Figure 6: Emissions as a Function of a Binational, System-Wide Price on Carbon Dioxide Emissions

Figures 7 and 8, in contrast, highlight the importance of modeling the transmission system. Figure 7 shows the predicted effects of the Regional Greenhouse Gas Initiative on carbon dioxide emissions from the electric power sector in the ten state regulated region (not the entire region), using three different models. Each point plotted on this graph is a weighted average of the sixteen representative hours that we model. The DC model predicts larger carbon dioxide emission reductions than does the AC model, and the model with no transmission constraints predicts much larger reductions. Figure 8 is different from Figure 7 in that it shows the predicted effect of RGGI on the sum of emissions inside and outside of the RGGI region, and it shows it as a percentage of the predicted emissions at a carbon dioxide price of $0. At a price of $25, the DC

[2] All figures and tables of results in this report assume a sulfur dioxide price of $700 per metric tonne and a nitrogen oxide price of $2000 per metric tonne, unless otherwise noted. Unless otherwise specified, results are based on our alternating-current model.

model predicts an increase in total emissions while the AC model predicts a decrease. At a price of $50, the AC model predicts an overall emission reduction twice as large as the reduction that the DC model predicts.

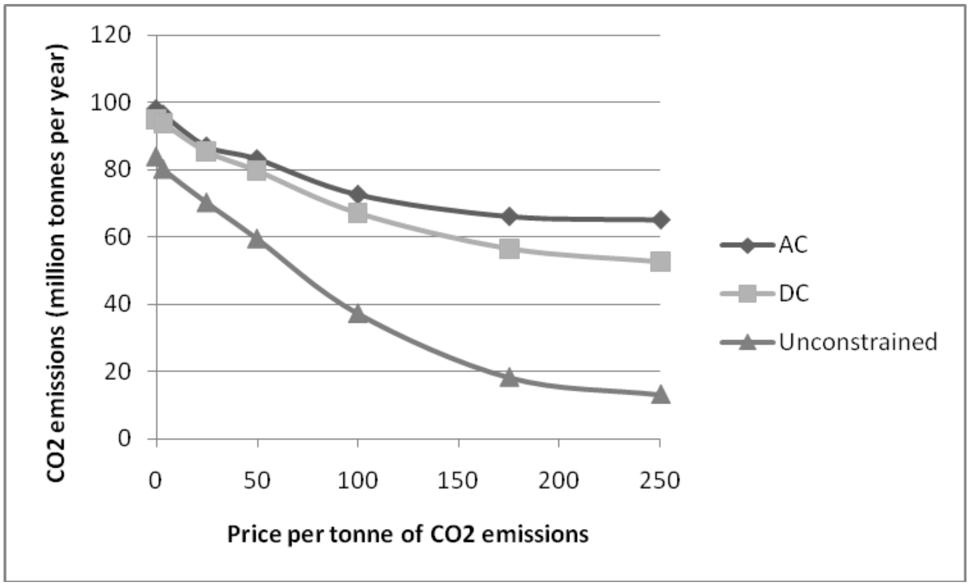


Figure 7: Predicted Effect of Regional Greenhouse Gas Initiative on Carbon Dioxide Emissions in the Regulated Region

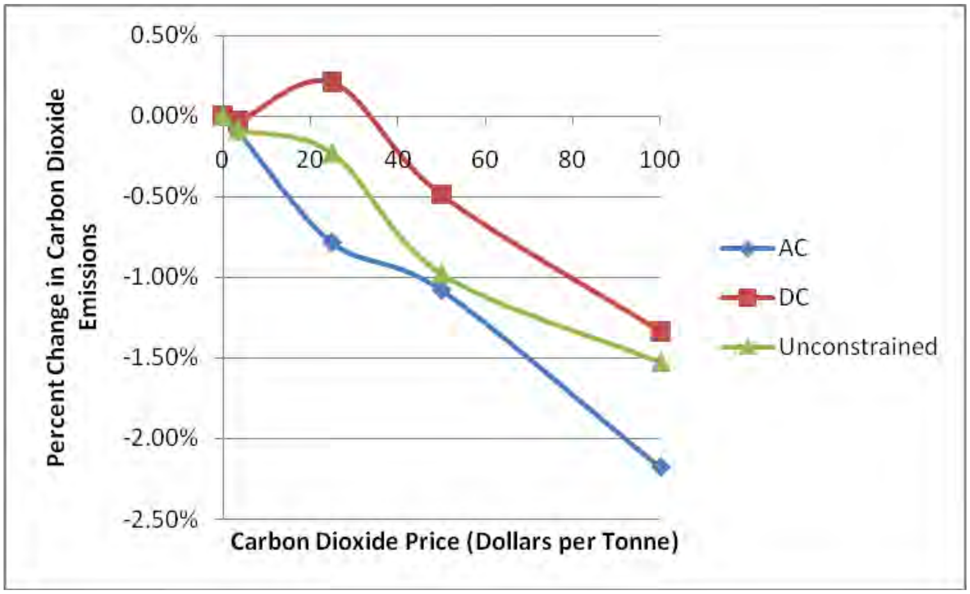


Figure 8: Predicted Effect of Regional Greenhouse Gas Initiative on System-Wide Carbon Dioxide Emissions, for Carbon Dioxide Emission Prices Between $0 and $100

4.2 “Leakage” under the Regional Greenhouse Gas Initiative

The top line in Figure 9 again shows the AC model’s predictions of total emissions from the electric power sector in the modeled region, as a function of the RGGI permit price. Figure 9 decomposes this total into emissions within the RGGI states and emissions elsewhere in the modeled region, revealing leakage. For example, at a RGGI permit price of $3.51, which was the price in the March 18, 2009 auction of RGGI permits, our AC model predicts that emissions from power plants within the RGGI states are reduced by 1.6 million metric tonnes per year, but that emissions from power plants in surrounding states and adjacent Canadian provinces are increased by nearly as much, 1.3 million tonnes, for a net reduction of 0.3 million tonnes in the modeled year. However, this is not the end of our story about RGGI. We will consider its cost for reducing CO_2 in comparison to a region wide policy below.

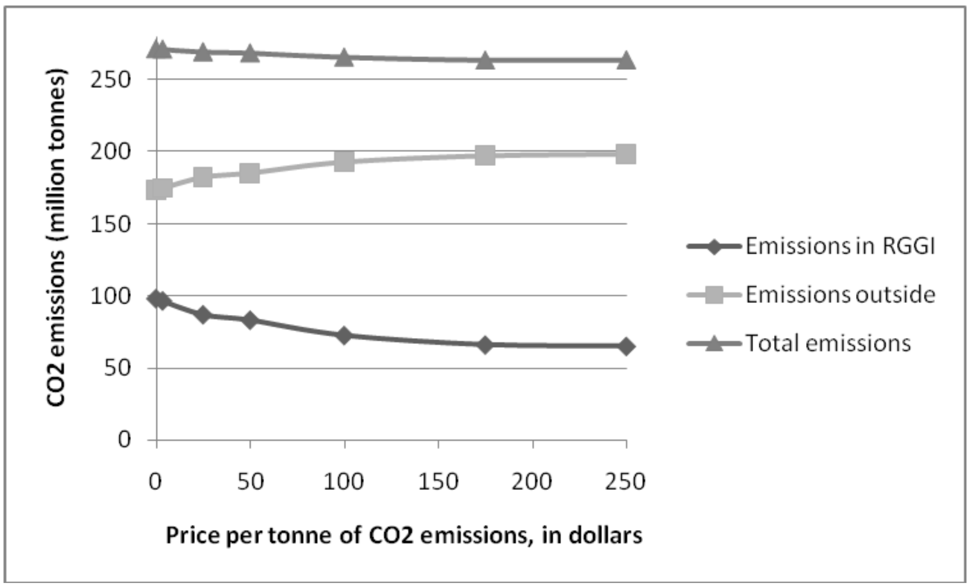


Figure 9: Predicted Effect of Regional Greenhouse Gas Initiative on Carbon Dioxide Emissions in the Participating States and in Nearby Non-Participating States and Provinces

4.3 Universal and partial application of a carbon dioxide price

Policymakers can impose a price on all generation units or on just a subset of the units. Thus far, we have considered a price applied to all generation units (a “bi-national” price) and a price imposed only on the generation units in the RGGI region. We will consider these two policies further, along with three other policies: a U.S.-only price, a Canada-only price, and a price applied throughout the modeled region but only to generation units with capacities above 25 megawatts (MW). Many units with capacities of 25 MW or less are exempt from certain emission regulations in the United States. All such units are exempt from the RGGI.

Our U.S.-only policy is not a valid representation of a nationwide U.S. policy, because the power system varies geographically and because much of the United States is farther from Canada or Mexico than the modeled portion of the U.S. is from eastern Canada. Our Canada-only policy is not a valid representation of a nationwide Canadian policy, although the resemblance may be closer since much of Canada's generation capacity and load are in our model and the portion not included may be similarly well connected to the U.S. Rather than accurately representing national policies, our U.S.-only and Canada-only policies roughly represent the effects of nationwide policies within in the modeled region, and also serve as generic examples of policies that apply in one region but not in a neighboring region.

Figure 10 provides the information for our comparison of the five simulated policies. It plots cost versus quantity of emission reductions under each of these policies. We define the cost of an emission reduction policy as that policy's effect on the total cost of providing the quantity of electricity demanded. We do not include carbon dioxide emission prices in the cost because they are transferred to the government or another party, so they have no net effect on social surplus.[3]

The curves in Figure 10 are not supply curves, since the vertical axis measures system-wide, aggregate variable cost. We might wish to instead plot supply curves by putting the derivative of aggregate cost with respect to aggregate emission abatement on the vertical axis, but cannot because we know it only for the bi-national policy. Under the "bi-national" policy, it is equal to the emission price. For the other policies it is not, because of leakage.

The marginal cost of emission reductions is the slope of each line. The average cost of emission reductions at any point on one of the curves is the slope of a ray from the origin to that point. For any quantity of emission reduction, the bi-national carbon dioxide emission price, which applies to all generation units, achieves that reduction at lowest cost. Even though generation units with capacities of 25 MW or less constitute only 3.7% of fossil-fueled generation capacity in our model, exempting these units increases the cost of achieving any quantity of total emission reduction by approximately 50%, primarily because of emission leakage to these small generators. Similarly, a U.S.-only policy achieves any given quantity of emission reduction at approximately 50% greater cost than does a bi-national policy.

The cost of achieving any given quantity of emission reductions is several times higher with a RGGI-only or Canada-only policy than with a bi-national policy, partly because these are substantially smaller regions and partly because of leakage.[4] For any given quantity of emission abatement, a policy without leakage normally has an average abatement cost lower than its emission price (since without leakage the emission price is also the marginal abatement cost). However, the average cost of the emission reductions from RGGI is $11 at a permit price of $3.51 and $53 at a permit price of $10. Our model predicts that a Canada-only emission price of $25 actually increases overall emissions in the region because generation in Canada is replaced with more polluting generation in the United States. Of the Canada-only carbon dioxide emission

[3] We do however include sulfur dioxide and nitrogen oxide emission prices. If one of these emissions increases or decreases as a result of a policy change, it has health and environmental effects that we do not otherwise consider. Instead of considering it separately, we include it in the objective function by assuming that the marginal damage from these emissions is equal to the price of these emissions, which in our simulation is $700 for sulfur dioxide and $2000 for nitrogen oxides. This has little effect on the results, compared to assuming zero external marginal damages from these emissions.

[4] An additional reason for the high cost of emission reductions, in the case of RGGI, is that leakage to small generation units may occur because they are exempt from the policy.

prices we model, the one that achieves emission reductions at lowest average cost is $50. It achieves emission reductions at an average cost of $112 per tonne.

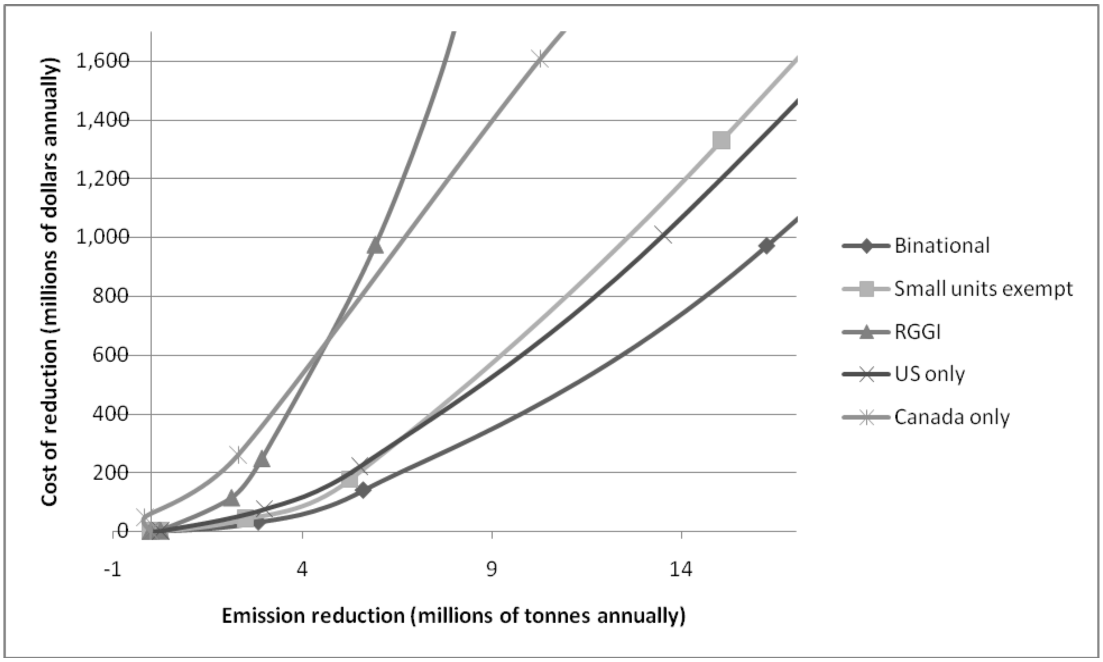


Figure 10: Aggregate Variable Cost of System-Wide Aggregate Emission Reductions Under Five Policies

We should warn that our model might overestimate leakage in the short run because of constraints on flows between ISOs and RTOs, and hence might also overestimate the costs of emission reductions from the policies that can result in leakage: the RGGI-only, Canada-only, U.S.-only, and large-generators-only[5] policies. The constraints on flows between jurisdictions themselves are inefficient and raise costs and the ISOs in the Northeast are working together and committed to eliminate the "seams" issue in the near future. Our simulation in effect assumes that the "seams" issue is resolved and electricity is efficiently dispatched across the entire Northeast. In addition, the ideal model would combine both thermal and voltage limits that fully match the real system. Our model has thermal limits on the interfaces where such limits historically have bound most restrictively. However, there could be other thermal limits that in reality will bind in the event Canada-only, U.S.-only, or RGGI-only emission prices, but that are not included in our model. Note also that we do not consider the long-run elasticity of electricity demand, a topic that is taken up in Section 5. Whether our model accurately predicts leakage or not, policymakers in the country with the more stringent carbon dioxide emission regulation can prevent leakage across the U.S.-Canada border by applying a tariff on imported power.[6]

[5] This would affect the analysis of the large-generators-only policy to a lesser extent than it would affect the analysis of regional policies, since small generators are spread throughout the modeled region, making transmission less important for leakage to those generators.
[6] The RGGI states may be prohibited by federal inter-state commerce laws from addressing leakage from other U.S. states in this way.

4.4 *Effect of carbon dioxide regulation on sulfur dioxide and nitrogen oxide emissions*

Figure 11 shows the demand curves for sulfur dioxide emission permits at carbon dioxide prices of $0 and $100. These demand curves assume each unit has a constant sulfur dioxide emission rate. They are extremely short-run demand curves. In a matter of hours, days, or weeks, generators can change their sulfur dioxide output rate by switching to coal with a different sulfur content.[7] Therefore, over a period that allows for such a fuel change, the curves would be more elastic. Nonetheless, the *shift* shown in Figure 11 is valid in the longer term as well. It shows that the carbon dioxide emission price can significantly shift the demand curve for sulfur dioxide permits. Under a cap and trade program on sulfur dioxide emissions, a carbon dioxide price would reduce the price of sulfur dioxide permits, which could induce unit owners to switch to higher-sulfur coal and turn off their emission control devices, since the latter are costly to operate. This could be avoided by switching to a sulfur dioxide emission fee or by tightening the cap on sulfur dioxide emissions. If the sulfur dioxide permit price were $700 per tonne with no carbon dioxide price, keeping it there with a carbon dioxide price of $100 per tonne would require reducing the quantity of sulfur dioxide emission permits by 11%, as shown graphically in Figure 11. Even then, if the carbon dioxide regulation were a cap and trade program, fluctuations in the price of the carbon dioxide permits could also cause large fluctuations in the prices of the sulfur dioxide permits.

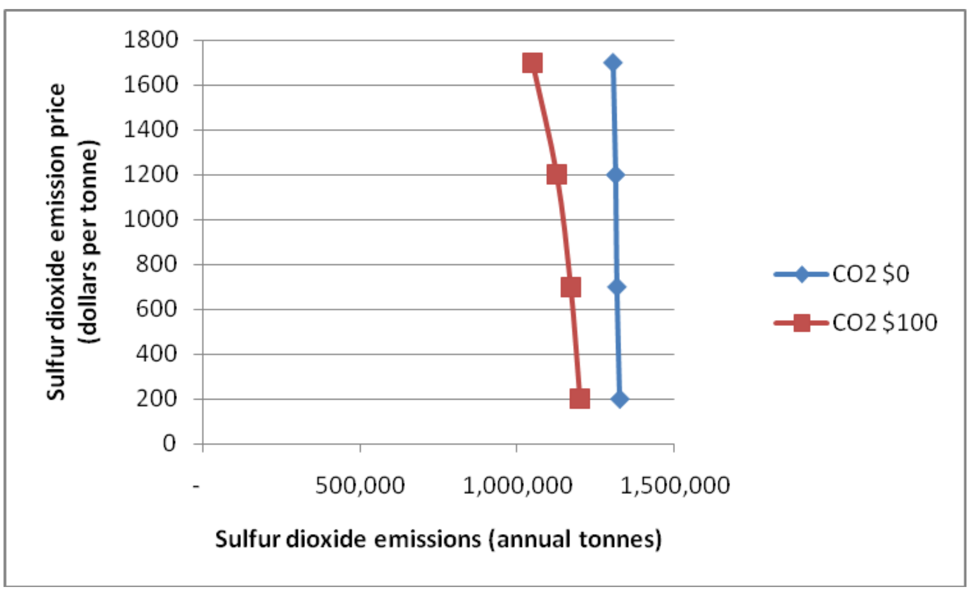


Figure 11: Effect of Carbon Dioxide Price on Sulfur Dioxide Permit Demand Curve

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[7] Generation units with "scrubbers" for flue-gas desulfurization can also turn them off or on. However, the variable cost of operating a scrubber is approximately $150 to $210 per metric tonne of sulfur dioxide removed (Hart, 2009), and our sulfur dioxide permit demand curves in Figure 10 start at a price of $200 per metric tonne, so operators would leave the scrubbers on over all but the extreme low end of the range of the curves shown.

The price of carbon dioxide could similarly interact with the price of nitrogen oxides: keeping the price of nitrogen oxide permits at $2000 while increasing the carbon dioxide price from $0 to $100 would require reducing the quantity of nitrogen oxide permits by 10%.

4.5 Emission price volatility under a cap and trade program

A cap-and-trade program is susceptible to price volatility in response to changes in expected permit supply or demand. One type of event that could cause such a change in expectations is a drought, which reduces the amount of hydropower, one of the two largest power types that are associated with virtually zero carbon CO_2 emissions. In the forty-year period ending in 1999, there were four "severe" or "extreme" droughts in the northeastern United States, lasting up to five years, and associated with a reduction in rainfall of approximately 20% or more.

Figure 12 shows the effect of a drought that reduces hydropower production by 20%, estimated using our AC model. In a three-year true-up period of the RGGI policy, if the amount of emission reduction required by the policy is 1.6% relative to business as usual, a drought raises the predicted permit price from the current price of approximately $3.50 (blue curve) to approximately $20 (red curve). If the required emission reduction is 10% from business as usual, a drought raises the predicted permit price from approximately $20 to approximately $60.

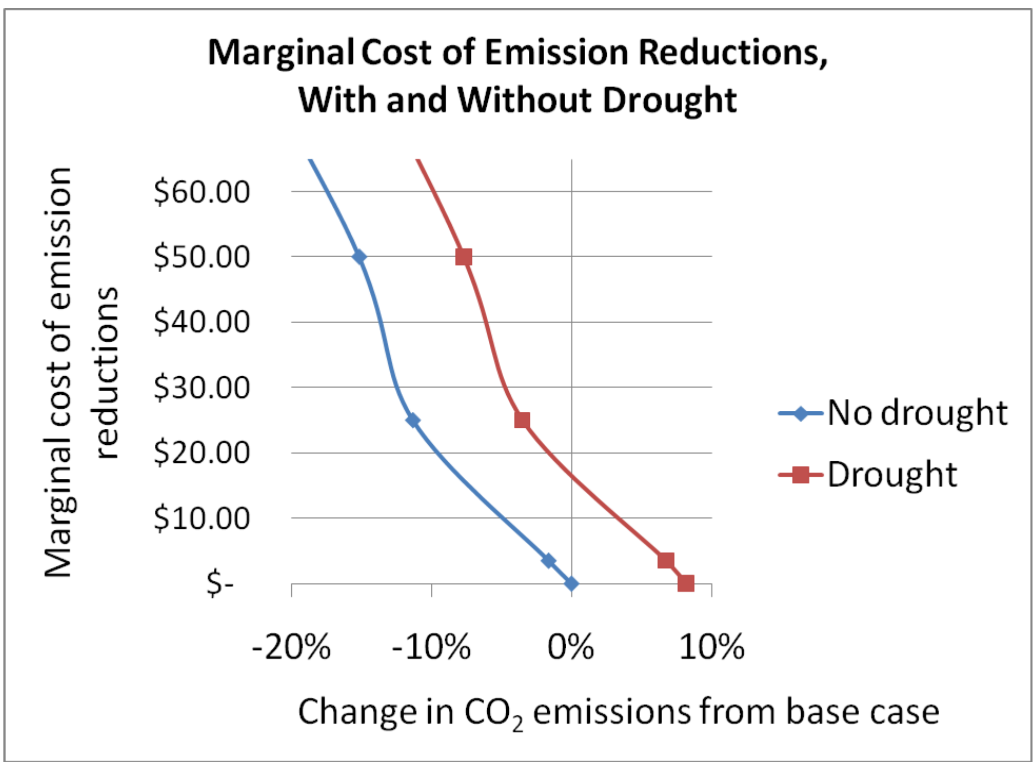

Figure 12: The Effect of a Drought on the Demand Curve for Emission Permits within the Ten RGGI States

Our analysis ignores two other components of the RGGI policy that should reduce CO_2 emissions. First, power plant owners in the RGGI region may satisfy some of the emission reduction requirements by purchasing offsets. Second, the states may use some of the revenues from the sale of RGGI emission permits to fund programs that help energy customers to improve their energy efficiency and consequently to reduce the demand for permits.

4.6 Higher average costs resulting from volatility of permit prices

A cap-and-trade program is susceptible to permit price volatility. The potential for drought, such as the recent prolonged southeast drought that reduced hydroelectric production by about 50%, is one potential source. Another possibility is the shutdown of multiple nuclear plants because of a threat of terrorist attacks. One of the largest potential causes at the national and bi-national levels is a change in the price of natural gas.

Permit price volatility increases the average cost of emission abatement. We will see this using Table 1, which presents the emission reductions and average costs of emission abatement under a bi-national emission reduction policy. If there were an emission tax of $25 per tonne or a cap-and-trade program with a constant permit price of $25 per tonne, the emission reduction would be 2.84 million tonnes per year and the average cost of the abatement would be $11.20 per tonne. If instead there were a cap-and-trade program with a permit price that was $3.51 for 52% of the time and $50 the other 48% of the time, the emission abatement per year would be the same, but the average cost of the abatement would be $23.85 per tonne.

Table 1: Emission Reduction and Average Cost of Emission Reductions Under a Binational Policy

Emission price (dollars per tonne)	Emission abatement (millions of tonnes per year)	Average cost of abatement (dollars per tonne)
0	0	N/A
3.51	0.26	1.69
25	2.84	11.20
50	5.60	24.99
100	16.22	59.87
175	40.12	100.06
250	51.29	117.55
10000	61.09	165.10

4.7 Effects on SO_2 and NO_X emissions in New York City and Boston

Because SO_2 and NO_X are criteria pollutants whose impacts are most dramatic close to where they are emitted, it is interesting to consider the amount of these pollutants that are created in high population areas. We will consider the emissions that would occur at several carbon dioxide prices but at a constant sulfur dioxide emission price of $700 and a constant nitrogen oxide emission price of $2000, as if generation unit owners faced emission fees of these magnitudes. New York City and Boston are the two largest cities that can be most closely identified in this model network. Figure 13 shows how SO_2 and NO_X emissions change in these two cities with various CO_2 prices. The blue lines show local emissions under a carbon dioxide price that is applied to the entire modeled region. The green lines show local emissions under a carbon dioxide price applied only to RGGI. Let us consider Boston first, shown on the right. Sulfur dioxide and nitrogen oxide emissions decrease montonically as the carbon dioxide price increases. Figure 14, which shows the generation by fuel type for various CO_2 prices, reveals the reason this happens. For each CO_2 price, the bar on the left denotes the generation mix when CO_2 prices are applied to all generators in the model, while the bar on the right is the case when CO_2 prices are applied only to generators in the RGGI area. As the carbon dioxide price increases, the use of coal-fired generation in Boston, with its high SO_2 and NO_X emission rates, decreases.

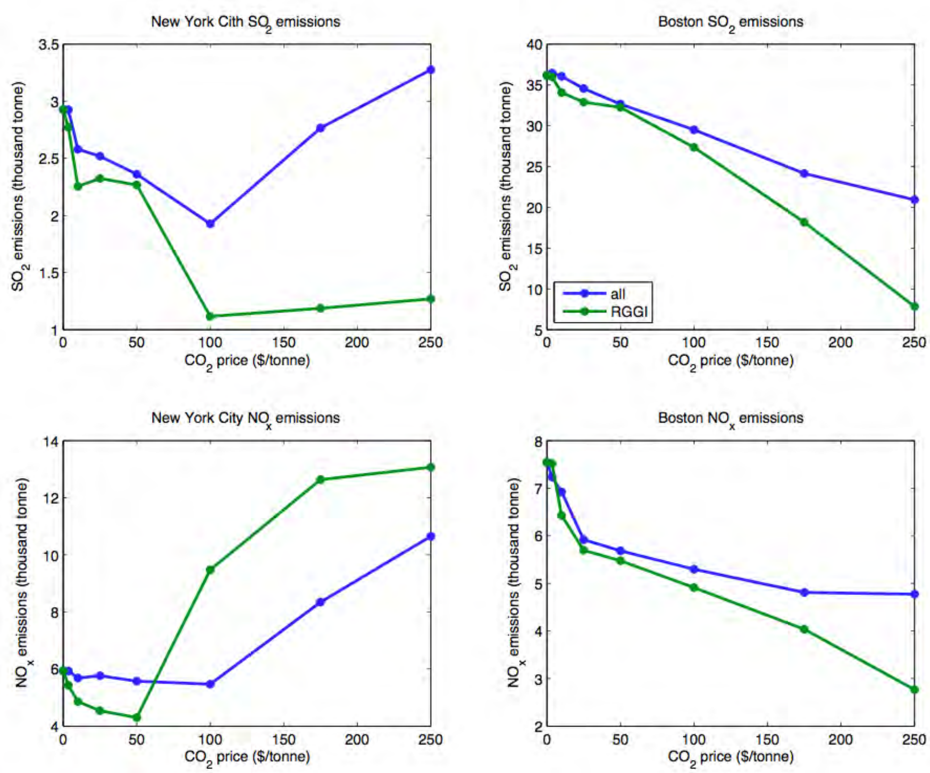

Figure 13: SO_2 and NO_X emissions in New York City and Boston

Now let us consider New York City, shown on the left in Figures 13 and 14. SO_2 and NO_X emissions decrease through a carbon dioxide price of approximately $100 (or $50 in the case of nitrogen oxide emissions under a RGGI-only policy), then increase thereafter. There is no coal-fired generation in the portion of New York City represented in these graphs. The decreases through a CO_2 price of approximately $100 occur because oil-fired generation decreases in favor of gas-fired generation in New York City and elsewhere as a result of the higher CO_2 emission rates at most oil-fired generators relative to most gas-fired generators. However, at CO_2 prices above approximately $100, the CO_2 price plays a larger role in the dispatch decision relative to the SO_2 and NO_X prices, so oil- and gas-fired generators with high SO_2 and NO_X emission rates in New York City are used to substitute for higher-CO_2-emitting coal-fired generation elsewhere.

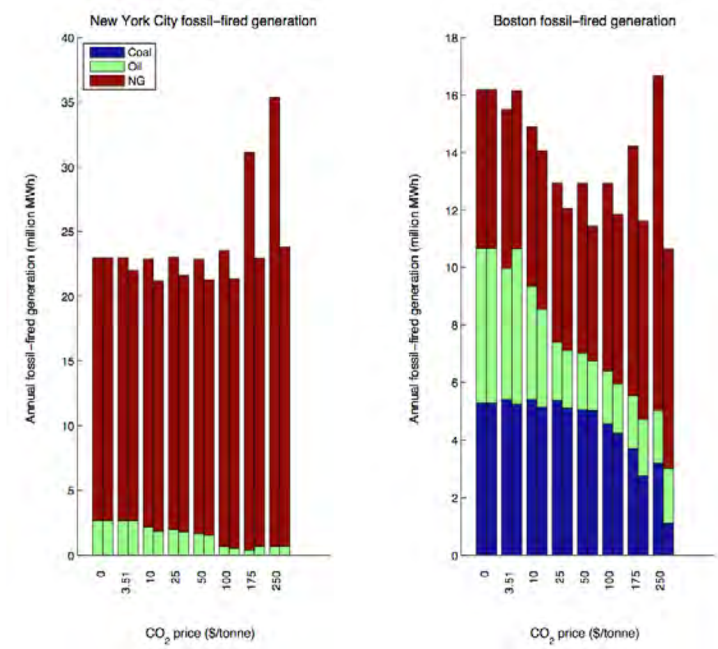

Figure 14: Fossil-fired generation in New York City and Boston

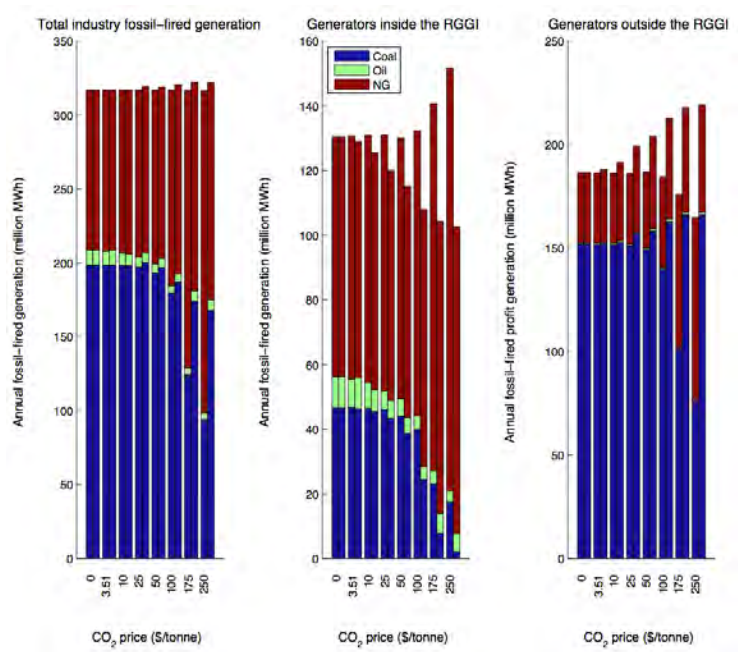

Figure 15: Fossil-fired generation in and out of RGGI

4.8 *Use of each fuel type*

Figure 15 demonstrates that when CO_2 costs are applied to generators in the RGGI area only, imports of electricity from outside the RGGI area increase while the number of MWh generated inside the RGGI area decreases. The increase in generation outside of the RGGI area occurs at both natural gas- and coal-fired generators. On the other hand, when CO_2 costs are applied to all generators in the model, coal-fired generation decreases everywhere and natural gas-fired generation increases.

5. Adding Long-Run Demand Response

In this section we explore the implications of the potential long-run demand response to the inevitably higher prices for electricity that will occur with binding CO_2 cap and trade. Although the Northeast power system is not representative of the national system, if one extrapolates to analyze the proposed national CO_2 cap and trade program and objectives, a number of conclusions can be drawn. We take the output from the simulations and fit a multi-equation statistical model that makes it possible to add a demand model. Thus, using the output from MATPOWER simulations, we estimate quantities of carbon dioxide, sulfur dioxide, nitrous oxides and average nodal electricity prices with linear regressions, given the prices of the various pollutants and electricity load as an input. The subscript i represents carbon dioxide for i=1, sulfur dioxide for i=2, and nitrous oxides for i=3.

$$Q_i = \alpha_i + \beta_{i,1} \text{ x } P_1 + \beta_{i,2} \text{ x } P_2 + \beta_{i,3} \text{ x } P_3 + \gamma_I \text{ x Load} \qquad (1\text{-}3)$$
$$LMP = \alpha_4 + \beta_{4,1} \text{ x } P_1 + \beta_{4,2} \text{ x } P_2 + \beta_{4,3} \text{ x } P_3 + \gamma_4 \text{ x Load} \qquad (4)$$

We also model demand response to changing electricity prices while assuming constant load growth of 0.59%, based on estimates from the New York ISO.[8]

$$Load_t = LMP_{Base}/WLMP_t + (0.0059 \text{ x } Load_{t-1}) \qquad (5)$$

This last equation is the cornerstone of our demand response, which is useful for calculating a long-run equilibrium in the electric power market. In the short run, there is almost no demand response from electric consumers, especially residential customers, as they are often tied into fixed-rate price contracts. In the long run, the elasticity of demand is close to -1, as rates adjust and customers have time to make investments in energy efficient appliances, energy-saving home improvements, etc. LMP_{Base} is the electricity price prior the first year of our simulation, before the imposition of carbon taxes or permits on a national scale. Weighted LMP, $WLMP_t$, is an infinite exponentially decreasing distributed lag of LMP prices estimated by our model and takes the form:

$$WLMP_t = (0.9 \text{ x } WLMP_{t-1}) + (0.1 \text{ x } LMP_{t-1}) \qquad (6)$$

[8] http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/NYISO_2009_Summer_Outlook__05212009_(2).pdf

Using this equation, load will not immediately adapt to changes in prices, and the impact of systemic price changes will be gradually adopted.

5.1 Estimation results

Linear regressions were estimated using 2061 output observations produced by modeling the electric power grid of the Northeast as various factors, such as emission prices and load, were varied. Quantities for emissions are in metric tonnes, emission prices are in dollars per metric tonne, average LMP is expressed in dollars per megawatt hour, and load is expressed as a fraction of expected load in 2011. (A load of 0.90 would mean that load is 10% lower than in 2011.) Tables 2-5 show the estimated equations for predicting the quantity produced of the three pollutants and average LMP.

Table 2: CO_2 Quantity

Adjusted R-Squared: 0.83

	Coefficient	T Stat	P-Value
Intercept	-267087436	-10.14	1.37E-23
CO_2 Price	-209440.87	-97.83	0
SO_2 Price	-1607.82	-4.86	1.29E-06
NO_X Price	-196.37	-1.78	0.0754
Load	550710813.1	20.89	4.81E-88

Table 3: SO_2 Quantity

Adjusted R-Squared: 0.95

	Coefficient	T-Stat	P-Value
Intercept	-272388.96	-1.70	0.089
CO_2 Price	-2688.94	-206.88	0
SO_2 Price	-38.73	-19.26	3.79E-76
NO_X Price	-3.22	-4.80	1.70E-06
Load	1700647.18	10.63	1.03E-25

Table 4: NO_X Quantity

Adjusted R-Squared: 0.93

	Coefficient	T-Stat	P-Value
Intercept	-147624.19	-6.80	1.33E-11
CO_2 Price	-292.85	-166.15	0
SO_2 Price	-3.12	-11.46	1.65E-29
NO_X Price	-2.32	-25.50	7.68E-125
Load	379223.95	17.47	7.55E-64

Table 5: LMP

Adjusted R-Squared: 0.99

	Coefficient	T-Stat	P-Value
Intercept	-123.01	-14.98	3.31E-48
CO_2 Price	0.705	1057.06	0
SO_2 Price	0.00187	18.13	2.96E-68
NO_X Price	0.000451	13.11	9.06E-38
Load	189.12	23.02	1.69E-104

These results are very much as would be expected. Increasing prices on any pollutant result in a reduction of the quantity produced. The simultaneous nature of pollutant production probably accounts for the significance of other pollutant prices in pollutant quantity estimation. Especially as prices on CO_2 permits increase, more generation shifts away from coal plants (especially older coal plants) resulting in a drop in other emissions as well. The LMP estimation shows that CO_2 permits have by far the largest impact on electricity pries; just over 70% of the price of a CO_2 permit is passed through to increased electricity prices.

5.2 Results

Using the results from an OLS estimation of equations (1) – (4) and incorporating equations (5) and (6) allows us to model the quantity of carbon dioxide and other pollutants produced as carbon dioxide permit prices are changed. Alternatively, we can examine what prices are necessary to meet carbon targets as specified in the Markey-Waxman legislation. The algorithm for estimating works as follows:

1) Given weighted LMP, load is estimated for the current year (t).
2) Given load and emission prices, pollutant production and LMP for year t are estimated.
3) Weighted LMP is calculated for year t+1.
4) Return to step (1)

Two simulations were run to investigate the effect of demand response to changing electricity prices: one without any demand response, meaning that load increased at a fixed rate of 0.59% every year, and one with the increase in load and load price response. Values of \$1000/tonne and \$2500/tonne were used for SO_2 and NO_X prices respectively throughout the model. An initial LMP of \$74, which includes a RGGI permit price of \$7 and load of 1 was used. Targets for CO_2 production are from the proposed Markey-Waxman legislation. 2012 requires a 3% reduction from 2005 levels, then additional annual decreases continue at 1.75% until by 2020 a total decrease of 17% is met. However, CO_2 emissions have declined in the U.S. since 2005, meaning that emissions in 2011 are already expected to be below 2016 requirements. This is due to a number of factors, such as improved heat rates in fossil-fuel plants, increases in wind generation, etc.[9]

[9] https://www.nyiso.com/public/webdocs/newsroom/current_issues/Foundation_to_Future_Opening_Remarks_SWhitley_04302009.pdf

Because of this, CO_2 permit prices will likely remain at the floor set in the Markey-Waxman legislation, at least in the near term. This means prices will start at $10/tonne and increase by 15% each year. In the absence of demand response, CO_2 prices increase above the floor starting in 2015. However, the validity of our model past this point may be questionable, since we allow for no construction of new power plants. Still, this illustrates the importance of allowing for demand reduction as electricity prices increase, as well as the importance of the floor on CO_2 permit prices. An additional wrinkle is that our model does not allow for permit banking which may, to a limited extent, offset the extremely high CO_2 prices seen in the model without demand response. Permits from the first few years, when CO_2 production is below target levels, may be saved for years when more CO_2 permits are required but unavailable.

Figures 16-18 compare our modeled emission response with and without demand response. With a demand response included, CO_2 levels stay well below limits set by the Markey-Waxman legislation due to a reduction in demand caused by the pass-through of CO_2 permit prices into electricity prices. Lacking this response, the scenario without demand response depends on increasingly high CO_2 prices (as illustrated in Figure 19), which also drives down SO_2 and NO_X emissions below the small reductions caused by decreased load and slightly elevated electricity prices in the demand response model. The consequences for electricity prices (LMP) and load can be seen in Figure 20. Lacking demand response, load and electricity prices constantly increase. With demand response, electricity prices increase slowly and load decreases in response. The magnitude of electricity price increases in the model lacking demand response vastly exceeds that of the demand response model, reaching $248 in 2020 versus $84.

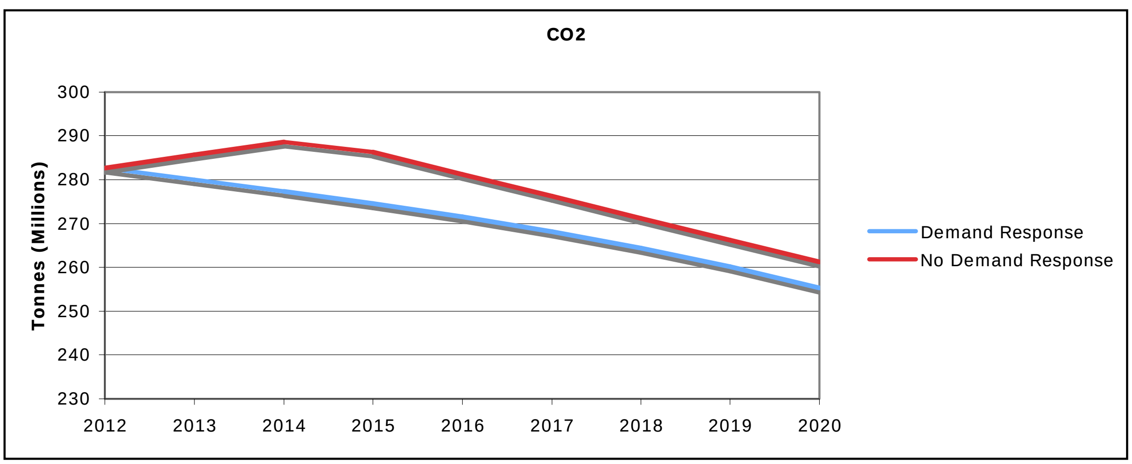

Figure 16: Estimated CO_2 emissions with and without demand response

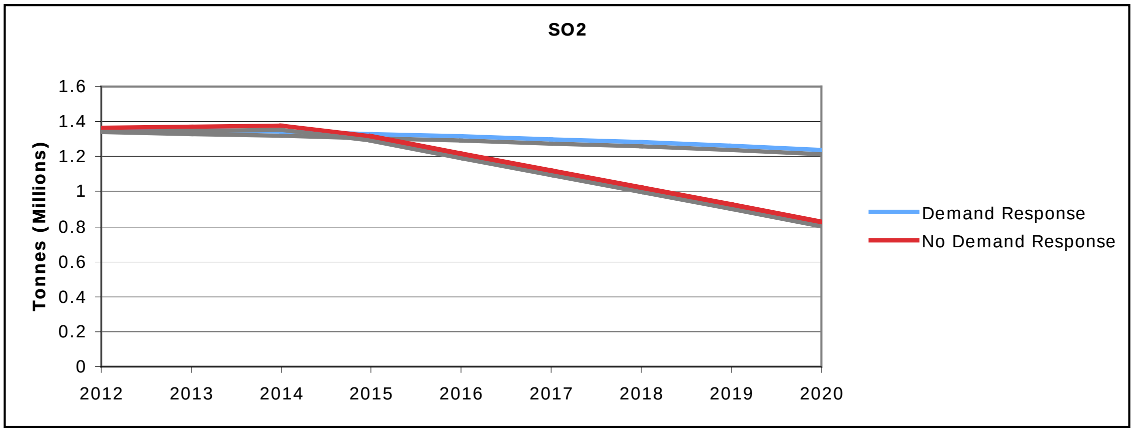

Figure 17: Estimated SO_2 emissions with and without demand response

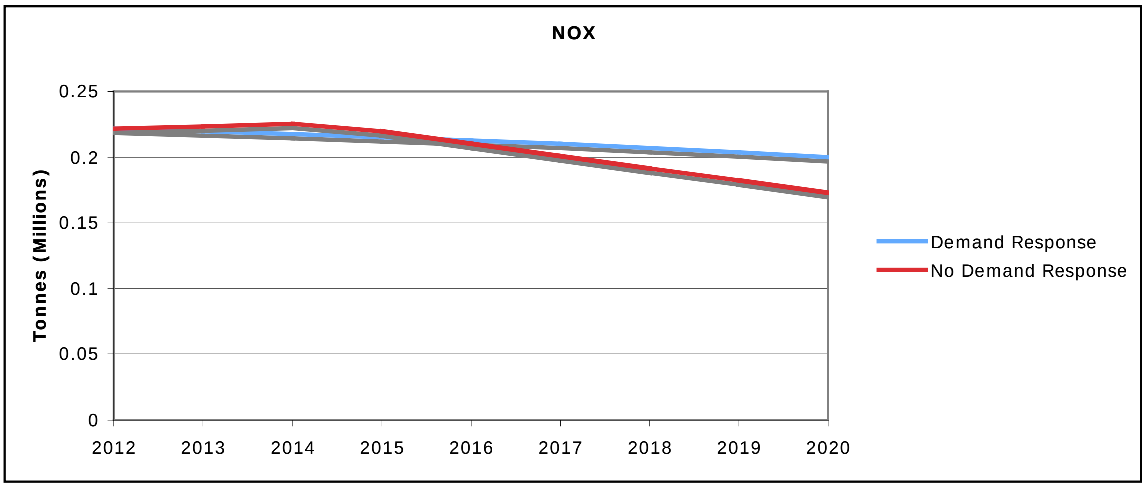

Figure 18: Estimated NO_x emissions with and without demand response.

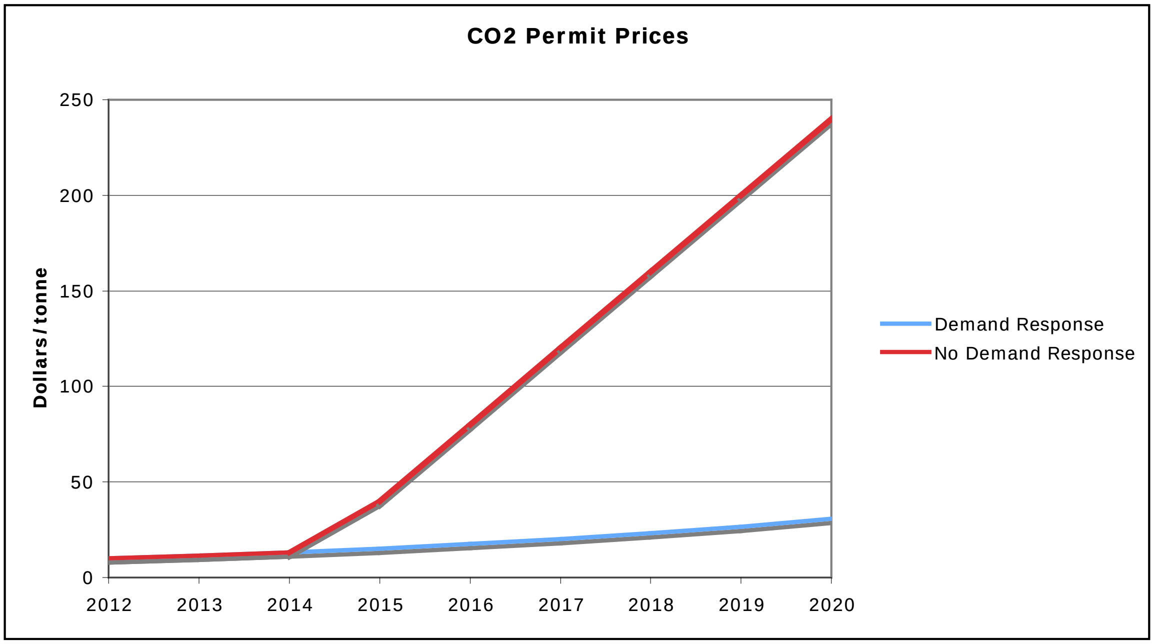

Figure 19: Estimated CO_2 permit prices with and without demand response

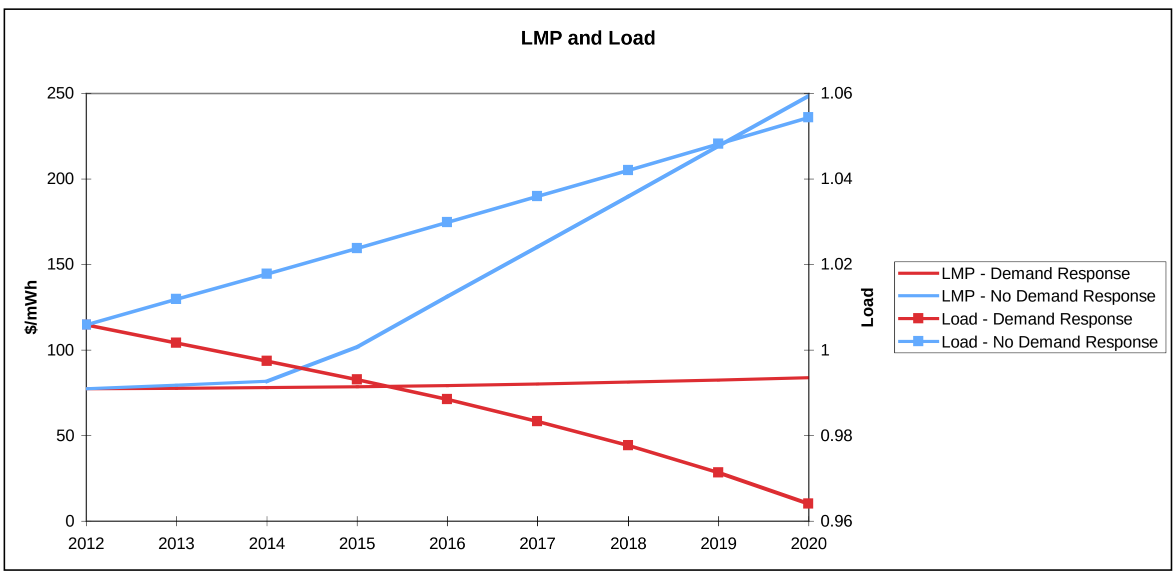

Figure 20: Estimated LMP and Load with and without Demand Response

6. Conclusions

The short-run demand for CO_2 allowances under a national cap-and-trade policy is likely to be extremely inelastic. Based on our simulations of the Northeast power system, with a policy applied to the entire region, compared to a price of $0, a $50 carbon dioxide emission price reduces demand for CO_2 allowances by 2% and a $100 price reduces demand by 6%. This extreme inelasticity suggests that a poorly designed cap and trade program could do major harm to the industry and the economy because prices in the permit market could easily explode in response to a shortage of permits. Thus, a careful analysis of the implications of cap and trade is warranted.

Based on the simulations done in this study, our conclusions are as follows:

- Leakage may be a major issue for regional cap and trade programs. Leakage is the tendency to shift power production from regulated generators that have to buy CO_2 permits to less costly unregulated generators that do not have to buy CO_2 permits.
- This is true both for the Regional Greenhouse Gas Initiative (RGGI) in the ten Northeastern States that have begun cap and trade for CO_2 and for the proposed U.S. national CO_2 cap and trade program (assuming the U.S. and Canada differ in stringency). In both cases, more power is imported from outside the regulated region after regulation is imposed. Note that the study assumes, as is anticipated, that seams problems between ISO/RTOs (boundary issues in operating the grid efficiently) are resolved. Currently, leakage is partly limited by these boundary constraints.
- Leakage dramatically raises the costs of reducing CO_2 emissions in comparison to the case where all generators face regulation, since load shifts inefficiently to potentially distant or less efficient unregulated generators.
- If generators of less that 25 MW capacity are exempted from regulation, as is done in RGGI, the costs of reducing CO_2 emissions increase dramatically because of within region leakage to those generators.
- AC and DC simulation runs generally produce similar results regarding the potential for leakage. This implies that future studies may be able to employ the more simple approximate DC approach to modeling large networks.
- A prolonged drought in the Northeast could severely impact CO_2 allowance prices in RGGI but would be buffered substantially in a national program.
- CO_2 allowance prices have a large impact on other emissions and the demand for allowances for SO_2 and NO_x.
- Although the Northeast power system is not representative of the national system, if one extrapolates to analyze the proposed national CO_2 cap and trade program and objectives, a number of conclusions are suggested:
    - The current system cannot produce significant reductions in CO_2 emissions in the Northeast at acceptable electricity prices in the short run because of inelastic demand for electricity. However, the long-run demand elasticity of -1 for electricity implies that a 10% increase in prices will cause a 10% decrease in

demand, mostly through energy conservation. Thus, demand reduction has significant potential for reducing CO_2 emissions from the electric power industry.

- In contrast to the short run situation, the long-run electricity demand response associated with the proposed cap and trade program of the Waxman-Markey bill is likely to dramatically limit price increases, even with the existing power system left in place.
- This implies that, in the long run, with additional investment in generation, transmission, and energy conservation, electricity prices will rise, but only slowly.
- Cap and trade has in the past and can in the future produce extreme allowance price-volatility and uncertainty for multiple pollutants if the cap is binding. Generators would likely prefer the certainty of pollution taxes for investment planning.
- However, it is possible that the price floor of the Waxman-Markey bill (CO_2 allowances are proposed to sell at auction for a minimum of $10 in 2012 rising at 5% per year in real dollars) will determine the price of allowances for a number of years after 2012 since the 2005 base year for calculating CO_2 reductions does not account for existing regional programs to reduce emissions such as RGGI, and the response to the likelihood of future CO_2 regulation that encourages pre-adaptation of the generation fleet, etc., so 2012 emissions are likely to be well below the cap.
- If this conclusion (based in part on a long-run demand response) is correct, the proposed CO_2 regulation will act more like a CO_2 tax and provide predictable incentives for new generation and planning.

Finally, this research suggests two critical research needs. First, based on the strong interaction effects between the demand for CO_2, NO_x, and SO_2 permits, as well as the difficulty in modeling the de-commitment of generators at high permit prices, a robust planning tool is needed that can solve the unit commitment problem by simultaneous optimizing over many sequential OPFs, that can also incorporate the spatial aspects of environmental modeling to predict ambient pollution for fine particulates and ozone, can optimize investment, and can handle short and long-run demand response, realistic networks and contingencies. Second, given the likelihood of national pollution allowance markets for CO_2, a detailed national model is needed that correctly models network flows to explore the issues raised in this report on a national level.

Appendix

A1. Introduction to our sources of data on generation units
The generator data at each bus is a combination of data from Energy Visuals, Inc.; Allen, Lang, and Ilic (2008); and the Environmental Protection Agency (2007). Our data on generation units purchased from Energy Visuals, Inc, came from the 2006 reliability planning process of the Multiregional Modeling Working Group, the group responsible for examining the adequacy of the electric power system in the Eastern United States and Canada under the auspices of the North American Electric Reliability Council. The data consists of the units projected to be operational in the summer of 2008. There were approximately 2000 such units in the region we model. For each unit, we have name, maximum and minimum real and reactive capability, fuel type, fuel use per MWh of output, fuel price in 2007, longitude, and latitude.

A2. Assignment of generation units to buses
We knew to which of the 36 buses Allen, Lang, and Ilic (2008) had assigned some of the generation units. We assigned the others by geographic proximity. Then, at each bus, we scaled the real-power capacities of all fossil units by a constant such that our maximum real-power capacity total at each bus matched the total from Allen, Lang, and Ilic, produced as described above.

A3. Fossil-fueled real-power generation capacity at each bus
Real power output of fossil-fueled generators is determined by the constrained cost-minimization problems described elsewhere in this manuscript. We calculate the total amount of fossil-fueled real-power generation capacity at each bus using data from Allen, Lang, and Ilic (2008). At each of their 36 buses, they report total real and reactive generation capacity (in the second-to-last, fifth, and sixth columns of the generation block of their appendix), total real and reactive generation in the summer peak-load hour that they model (in the third and fourth columns of the generation block of their appendix), and approximate percentage of that real-power generation coming from each fuel type (coal, gas, oil, nuclear, hydro, refuse, wood, and wind; in their Table VI). At buses with more than 0% of their real-power generation from fossil fuels (coal, gas, and oil), we calculate fossil-fueled real-power capacity as the total real-power generation capacity minus generation from non-fossil sources.[10]

A4. Availability of Fossil-Fueled Generators in Each Hour Type
Generation units are sometimes not available for operation because of maintenance or repair. We scale down the maximum and minimum real-power capability of each fossil-fueled generation unit using an availability rate. We start by multiplying the real and reactive power capacity of all fossil fueled units by 0.9613, which is the proportion of the time they were not having unplanned outages in 2006 (North American Electric Reliability Council, 2007). Then we multiply their capacities by an availability modifier specific to the hour type, as shown in Table A1. These availability modifiers bring the average availability of the units to the average reported by the North American Electricity Reliability Council. They differ from one in proportion to the amount

[10] This produces estimated fossil-fueled generation capacity of 93,772 MW. If instead we had calculated fossil-fueled real-power capacity as total real-power generation capacity times the percent of generation coming from fossil fuels, the total would have been 92,515 MW.

by which the load in their hour type differs from the system-wide load in the summer peak hour type.

Table A1: Availability Modifiers of Fossil-Fueled Generation Units, by Hour Type

Hour Type	Availability Modifier of Fossil-Fueled Units
FALL (Oct, Nov)	
Peak	0.93
High	0.90
Medium	0.87
Low	0.83
WINTER (Dec−Feb)	
Peak	0.96
High	0.93
Medium	0.90
Low	0.85
SPRING (Mar, Apr)	
Peak	0.93
High	0.90
Medium	0.87
Low	0.83
SUMMER (May−Sep)	
Peak	1.00
High	0.94
Medium	0.89
Low	0.83

A5. Non-fossil-fueled real-power generation capacity available at each bus
The economics of using or "dispatching" non-fossil fueled generation units (those relying on hydro, nuclear, refuse, wood, or wind) are different from the economics of dispatching fossil-fueled units. For nuclear, refuse, wood, and run-of-river hydropower units, the marginal operating cost of operation is typically close to zero, or else negative. We model non-fossil-fueled units as having marginal cost of zero[11], but we adjust their maximum capacities according to the hour type, as shown in Table A2. For the nuclear units, these maximum capacity adjustments primarily represent outages for refueling and other maintenance, which are most common in the fall and spring. For the hydro units, these adjustments represent the output decisions that result from water availability, environmental constraints on river flow, and intertemporal optimization of the use of available water. For wind, refuse, and wood, each of

[11] A result of having a marginal cost of zero is that the unit generates at its maximum capacity all or almost all of the time.

which constitutes only a miniscule proportion of total generation capacity, we assume that output does not vary by hour type.

Allen, Lang, and Ilic report the approximate output from each non-fossil generator type at each bus during the summer peak hour that they model, ignoring types that provide less than a few percent of the output at the bus. We take this output as the maximum output in any hour type from that generation type at that bus, since the summer peak hour is the hour with greatest total demand.[12]

For hydro, the adjustment to hourly demand in Table A2 makes total capacity factor (output divided by capacity) for the year equal to that reported in NERC (2007). The hydro adjustment factors deviate from 1 in proportion to the amount by which load during the respective hour type deviates from load during the summer peak hour type.

For nuclear, the adjustment to hourly demand in Table A2 makes total capacity factor for the year equal to the weighted equivalent availability factor[13] of 0.8899 reported in NERC (2007). The nuclear adjustment factors are the same for all hour types of a season because nuclear plants generally have constant output when they operate. They deviate from one in proportion to the amount by which the load in the seasonal peak hour type deviates from the load in the summer peak hour type. Allen, Lang, and Ilic report the amount of non-fossil-fueled (hydro, nuclear, wind, refuse, and wood) generation during the summer peak demand hour that they simulate. In our simulation, real power output of the non-fossil-fueled generators is simply a function of hour type. For nuclear, wind, refuse, wood, and run-of-river hydropower units, this is because the marginal operating cost of these generators is typically close to, or less than, zero. For hydro units with dams, this is because the output per hour is a result of water availability, environmental constraints on operation, and intertemporal optimization of the use of available water, rather than simply a function of marginal operating cost as for fossil-fueled units. Table A2 below shows how we adjusted the output of non-fossil-fueled generators in each hour type, after first multiplying each by another constant.

[12] For the hydro units taken together, this output is approximately 63% of the output that the units can produce when they all have an abundance of water. Sometimes, in reality, they do together produce more than this amount of power, but much of the variation in water availability does not correlate with our hour types. Average hydropower output per month is close to being constant. Even in the spring, when snow is melting, northeastern hydropower output is only about 5% higher than output in other seasons. Our model does not represent this seasonal difference, but its effect on the results would be small.

[13] Roughly speaking, an “availability factor” indicates the proportion of the time a unit is not out of operation for maintenance or repair.

Table A2: Real Power Output of Non-Fossil Fueled Generators by Hour Type as a Proportion of Summer Peak Output

Hour Type	Hydro	Nuclear	Wind, Refuse, Wood
FALL (Oct, Nov)			
Peak	0.97	0.73	1
High	0.96	0.73	1
Medium	0.95	0.73	1
Low	0.93	0.73	1
WINTER (Dec−Feb)			
Peak	0.98	0.84	1
High	0.97	0.84	1
Medium	0.96	0.84	1
Low	0.94	0.84	1
SPRING (Mar, Apr)			
Peak	0.98	0.75	1
High	0.96	0.75	1
Medium	0.95	0.75	1
Low	0.93	0.75	1
SUMMER (May−Sep)			
Peak	1.00	1.00	1
High	0.98	1.00	1
Medium	0.95	1.00	1
Low	0.93	1.00	1

A6. Reactive power capacity

The reactive power capacity at each bus has two parts. The first is a constant reactive power injection that represents the amount of reactive power that the transmission system produces or absorbs at each bus. In the reduced model, many of these constant injections are negative and have large magnitudes, as a result of the model reduction. The second part of the reactive power capacity is the reactive power capabilities of the generation units. Each unit has a range of reactive outputs it can produce, with a maximum that is typically positive and a minimum that is typically negative. We scale the capabilities of the fossil fueled units so that the total maximum and minimum reactive capacity at each bus, including the fixed injection and the reactive capabilities at the non-fossil-fueled units, is 10% farther from the fixed reactive power injection than the reactive power capacity totals in Allen, Lang, and Ilic (2008). We make the total reactive power ranges wider than in Allen, Lang, and Ilic's model in order to represent relatively inexpensive opportunities for providing reactive power that are not otherwise represented in our model, such as the installation of capacitors and inductors.

We assume that a generation unit can provide reactive power up to its maximum limit or down to its minimum limit costlessly if that unit is on. The only units we turn off in the optimization are coal-fired units, as part of the unit commitment process. Therefore, a need for reactive power can contribute to keeping a coal-fired unit on.

A7. Carbon dioxide emission rates of the generation units

From the fuel type, fuel use per MWh, and carbon content of different fuel types (Energy Information Administration, 2009) we calculated the CO_2 emission rate per MWh of each generation unit.

A8. Nitrogen oxide and sulfur dioxide emission rates of the generation units

The U.S. Environmental Protection Agency reports nitrogen oxide and sulfur dioxide emissions and generation output of most fossil fueled generation units with capacities over 25 MW. We matched the units in the EPA data with units in the Energy Visuals data based on name or owner name, fuel, and generation capacity. We used latitude and longitude to verify the matchups. For units not included in the EPA data, we assigned the following emission rates, which are the average emission rates of the units that appear in both the EPA and Energy Visuals data.

Table A3: Assumed Emission Rates for Units without Known Emission Rates (Metric Tonnes per Megawatt-hour)

Fuel	SO_2 rate	NO_X rate
Coal	0.006202	0.000824
Diesel Oil	0.000133	0.000927
Pipeline Natural Gas	0	0.000136
Residual Oil	0.000632	0.000504

A9. Amount of electricity demanded, or "load"

Table A4 presents the amount of electricity demanded ("load") by region in each hour type, as a proportion of the load in Allen, Lang, and Ilic's model of load during the summer peak hour. Load varies from one hour type to another, but is assumed to be perfectly inelastic in a given hour type, since few electricity customers face real-time electricity prices. The second column of Table A4 indicates the number of hours each hour type represents. For example, the fall "peak" hour type represents the 73 hours of October and November with the highest aggregate loads. The fall "high" hour type represents the 366 hours of October and November with the next-highest aggregate loads. Each hour type uses the average load in each region during the corresponding hours.

Table A4: Electric Load as a Ratio of Load in Summer Peak Hour by Hour Type and Region

	# of hours	New York	PJM-East	Ontario	Maritimes	New England
FALL (Oct, Nov)						
Peak	73	0.68	0.67	0.74	0.90	0.69
High	366	0.63	0.59	0.70	0.90	0.64
Medium	586	0.56	0.52	0.64	0.86	0.57
Low	439	0.45	0.42	0.53	0.74	0.43
WINTER (Dec−Feb)						
Peak	108	0.73	0.72	0.85	1.15	0.76
High	540	0.68	0.65	0.79	1.08	0.70
Medium	864	0.61	0.58	0.71	1.01	0.62
Low	648	0.50	0.48	0.60	0.91	0.49
SPRING (Mar, Apr)						
Peak	73	0.67	0.67	0.80	1.09	0.72
High	366	0.62	0.57	0.72	0.97	0.63
Medium	585	0.56	0.52	0.65	0.91	0.57
Low	439	0.46	0.43	0.55	0.84	0.45
SUMMER (May−Sep)						
Peak	184	0.87	0.87	0.87	0.87	0.87
High	918	0.75	0.72	0.75	0.84	0.72
Medium	1469	0.62	0.57	0.65	0.79	0.59
Low	1102	0.48	0.44	0.53	0.69	0.45

A10. Overview of numerical simulations

Numerical simulations of a highly simplified electricity network and air shed for Northeastern North America are exercised under varying combinations of variables allowing for meaningful research in two primary areas. The first area is understanding the policy impacts of environmental regulation, such as RGGI, when faced with various constraints on the electric grid, for example, a required reserve margin. The second area is to study varying methodological practices for modeling the electric grid by comparing AC and DC simulation results as well as examining line constraints.

A11. Simulation model variables

Eleven different variables, each discussed in detail in the following sections, are adjusted to create each individual simulated scenario. Some of the variables are binary, while others have multiple options. The variables considered in this modeling are:

1. AC or DC model (2 options),
2. transmission line constraints (2 options),
3. seasonal availability (2 options),
4. drought (2 options),
5. required reserve margin (2 options),
6. seasonal variation (16 options),
7. price of CO_2 allowances (8 options),
8. price of SO_2 allowances (4 options),
9. price of NO_x allowances (4 options),
10. the applicability of emission costs by geographic location (2 options), and
11. the applicability of emission costs by generation unit size (2 options).

Variables 1 through 3 are used to study the various methodological practices for modeling the electric grid, while variables 4 through 11 are used to understand the policy impacts of environmental regulation. A total of 27 * 42 * 8 * 16 = 262,144 scenarios are simulated.[14] In some cases, the results for only one value of each variable are reported in the main text. Each of the variables is explained in more detail below, in the remainder of section A11.

<u>AC and DC modeling</u>

A common simplified method of modeling a non-linear AC system is to model it as if it were a linear DC system. General Electric's MAPS and PowerWorld Corporation's Simulator are two software packages that use this modeling technique. DC systems remove voltage constraints and simplify stability constraints by imposing tighter flow constraints, known as "proxy limits," on transmission lines. These linear simplifications and proxy limits are designed to approximate the characteristics of the system under a specific pattern of operation. The more a system departs from that pattern of operation, the less accurate the results are by using these "proxy limits."

The reason to focus on this issue is that electric power systems are predominantly AC. Furthermore, the characteristics of an electric power network can strongly influence the effects of environmental policies that are applied to the power sector. The flows in such a network do not follow the shortest or most under-utilized route from where power is generated to where it is consumed. Rather, electricity flows follow laws of physics known as Kirchoff's Laws. The resulting constraints and flow equations affect which set of generation units satisfies electricity demand at the lowest cost in each moment. If emerging environmental regulations cause the electric system to operate under conditions substantially different than at present, then these constraints and flow equations also play a major role in determining the effects of a CO_2 emission regulation on emissions, cost, prices, profits, fuel use, and leakage.

So, for example, more stringent emission regulations are likely to result in less use of coal-burning generation units and more use of gas-burning generation units. Coal-burning and gas-

[14] Because the cases of applying a $0/tonne CO2 emission cost to different geographically located and sized generation units is redundant, there are only 245,760 unique scenarios.

burning generation units have different geographic locations, so more stringent environmental regulations may drastically alter the pattern of operation of the power system. In addition to dispatch changes inside the regulated region, leakage might occur across regulated and unregulated program boundaries. Leakage refers to the increased emissions from generators outside of a regulated region as a result of the increased marginal operating cost for generators inside a regulated region. This is of particular concern because leakage could potentially partially, or completely, offset the emission reductions from inside the regulated area with increased emissions from outside the regulated area.

Several studies of the economic and environmental effects of CO_2 regulation have been conducted to examine the issue of leakage. First, ICF International was hired by the RGGI participating states to use their Integrated Planning Model (IPM) to examine the impacts of implementing the RGGI. The IPM is a national model that includes very detailed data on every generator in the United States as well as emission rates for various pollutants, including CO_2. However, it assumes that transmission is unconstrained within regions (New York, for example, has five regions) and constrained by aggregate flow limits between adjacent regions (ICF, 2006). Though easier to solve with this simplifying assumption, the model does not even represent simplified DC flows.

Similarly, the Haiku model employed by Resources for the Future uses constraints between regions and it models generation using hundreds of characteristic "typical" generators including typical emission characteristics, but does not incorporate widely varying location specific characteristics (Paul, Burtraw, and Palmer, 2009).

Though the two models differ in how they treat fuel prices, investment, retirement of generators, etc., both studies suggest that leakage occurs but is not so great as to negate the intended CO_2 emission reductions by the RGGI.

Because every model is a simplification of reality, this research sets out to determine whether simplifications are acceptable, and which simplifications should be implemented. Detailed network modeling is quite difficult and may not be important enough to justify the effort required. One of the goals of this simulation is to test the hypothesis that it is important to model the network with the added realism of AC constraints and flow equations.

<u>Transmission Line Constraints</u>
In order to understand the importance of the transmission grid in the model (in comparison to IPM and Haiku modeling), simulations are run both with and without the enforcement of transmission line capacity constraints.

<u>Seasonal Availability</u>
A seasonal availability constraint on generators, which in reality is usually self-imposed because of the costs of starting-up and shutting-down some types of large thermal units, may be relevant for modeling purposes. In the basic optimal power flow (OPF) problem formulation, all generation units are assumed to be available to generate power between each unit's minimum and maximum generating capability, i.e. each generator must be dispatched to generate at least its minimum generating capacity in the optimal solution. This minimum generation imposition

for each generator is unrealistic because the actual dispatch of the electric grid never requires all generators to produce simultaneously at or above their minimum. Rather, generators bid into an auction the price at which they are willing to generate electricity and the dispatcher chooses the generators that will meet demand at the lowest cost to operate the electric grid. Therefore, this constraint is relaxed in the seasonal availability constrained dispatch scenarios by shutting down eligible units for an entire season.

Because gas- and oil-fired generation units have very short startup times, they are assumed to have a generating capacity ranging from zero at its minimum to the specific unit's maximum generating capability. Therefore, gas- and oil-fired generation units are not considered in the seasonal availability algorithm.

On the other hand, coal-fired generation units have a very long startup time and are therefore the only generators considered for shut down via the seasonal availability algorithm.[15] The candidate list for shutdown is built by ranking each coal-fired generation unit by its time-weighted mean profits over the entire season. The coal-fired generation unit with the least profits over the entire season is shutdown sequentially and each subsequent seasonal scenario is run with that generator unavailable. The process of removing the least profitable coal-fired generation unit continues until either the time-weighted mean objective function (i.e. the total cost of operating the electric system) increases, at least one of the seasonal scenarios results in an infeasible solution, or the candidate list is exhausted.

<u>Drought</u>

One type of event that could cause a change in generator availability expectations is a drought, which reduces the amount of hydropower available for dispatch. Hydropower is one of the two largest sources of electricity generation that produces virtually zero air emissions (the other being nuclear) and a drought could cause a significant shift in the optimal dispatching and emissions in a situation with high emissions prices.

A drought scenario is modeled by reducing hydropower capacity to be 80 percent of its maximum generating capacity under normal conditions. This percentage is chosen based on the past 40 years of data (ending in 1999) that recorded four "severe" or "extreme" droughts in the Northeastern United States. Each drought lasted between one to five years, resulting in a reduction of rainfall of at least approximately 20 percent of normal (the largest was a 50 percent reduction from normal from 1984–1985) (National Oceanic and Atmospheric Administration, 1999).

<u>Operating Reserve Margin</u>

In the true dispatch of the electric grid, a reserve margin of available generation in excess of actual demand is mandated to ensure electric reliability. The operating reserve margin is calculated by considering the loss of the largest generator operating on the system, which translates to about two to three percent, depending on the system. When a reserve margin is enforced in a scenario, each RTO maintains its own reserve margin, which is set to be three percent of the summer peak load for all seasonal scenarios.

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[15] Nuclear-powered generation units also have a very long startup time, but because they have a marginal cost of electricity generation close to zero, they are not considered in the seasonal availability algorithm.

Seasonal Variation

Electricity Demand

The electricity demand modeled in the simulations is based on 16 typical hour types that represent one calendar year. For each of the four seasons: fall (October–November), winter (December–February), spring (March–April), and summer (May–September), the total electric demand is further split into four bins: peak, high, medium, and low.

In each season, the hours of 2007 total system demand (i.e. the sum all RTO's demand) is ranked. The top five percent of the hours are the peak bin, the next 25 percent of the hours is the high bin, the next 40 percent of the hours is the medium bin, and the low bin is the lowest 30 percent of the hours. To create a single value for each bin in each RTO, the demand in each RTO is the mean of the demand in that RTO in the corresponding time bin. The number of hours per year that each of these 16 different demand levels occur is outlined in Table A4.

Table A4 also presents the amount of electricity demanded in each region and hour type, as a proportion of the summer peak electric demand as provided in Allen, Lang, and Ilic (2008).[16] Demand for electricity is highest during the hour that represents the highest-load hours of the summer and is lowest during the hour that represents the lowest-load hours of the fall. Electric demand is assumed to be perfectly inelastic because few electricity consumers currently face real-time electricity prices. Each hour type uses the average electric demand in each region during the corresponding hours based on 2007 hourly loads in each ISO.

Emissions Prices

Various CO_2, SO_2, and NO_X prices are considered in the simulations. These prices are chosen in order to cover a wide range of pricing (i.e. policy) scenarios — from very low to very high — to simulate both where prices have been recently and where they could go in the future. Furthermore, the wide range of prices considered allows the plotting of smoother curves when analyzing the impacts of price changes for each pollutant.

Table A5 outlines the eight prices used for CO_2. In particular, a CO_2 price of $3.51 is used because that is the auction clearing price from the March 2009 RGGI auction for 2009 allocation year CO_2 allowances.[17] The highest price chosen, $250 per metric tonne, is selected because at that price the dispatch of generators will certainly change and because it is an extremely high price relative to current experience, but is a level that might be reached in the future.

Table A5: Emission prices for CO_2 ($/metric tonne)

CO_2	0	3.51	10	25	50	100	175	250

Table A6 outlines the four prices used for each of SO_2 and NO_X. A non-zero price of SO_2 and NO_X is required because environmental standards are already in place for these pollutants, while

[16] The Allen, Lang, and Ilic´ model does not have any electricity demanded in the Quebec RTO, so its proportion is set to zero.
[17] At the time of running the simulations, this was the most recent RGGI auction price.

this is not the case for CO_2. Furthermore, the emission rates of the generation units assume a non-zero price of SO_2 and NO_x.

Table A6: Emission prices for SO_2 and NO_x ($/metric tonne)

SO_2	200	700	1,200	1,700
NO_x	500	2,000	3,500	5,000

Applicability of Emission Costs

By Geographic Location

One of the main worries for all regional environmental programs is leakage. As generators inside the regulated area are forced to pay for CO_2 permits, the prices at which they can offer to profitably sell power rises compared to the prices at which generators outside of the regulated region can offer to profitably sell power. This may cause emissions outside of the regulated area to increase, partially (if not completely) offsetting the emission reductions in the regulated area, as cheaper, more polluting, power is imported from the non-regulated area to the regulated area.

Therefore, in an effort to understand the impacts of leakage, CO_2 emission costs are applied in two different ways in the simulation model:

- to all generation units both in the United States and Canada, and
- only to RGGI area generation units.

In both of these cases, SO_2 and NO_x emission costs are applied to every generation unit in the simulation model.[18]

The geographic representation of the RGGI is approximate. One of the buses in the Allen, Lang, and Ilic model is enormous, and includes parts of states participating in the RGGI as well as parts of states not participating in the RGGI. The RGGI states included in this bus are all of Delaware and parts of New Jersey and Maryland. This bus is counted as being entirely outside of the RGGI area in order to maintain transmission constraints between RGGI and non-RGGI parts of the system.

By Generation Unit Size

As currently implemented, the RGGI exempts generation units with a nameplate capacity of less than 25 megawatts (MW). Therefore, simulations are run both enforcing and not enforcing this size limitation to evaluate the impact of such exemptions of relatively small generation units.

[18] Canada has its own SO2 and NOx regulations, though it works closely with the United States because about half of the acid rain in eastern Canada comes from the United States. For simplicity, it is assumed that all generators, both in the United States and Canada, face the same SO2 and NOx prices [7].

A12. Optimization Formulation Representing Generator Dispatch

The electricity system simulation software[19] is written in the MATLAB programming language[20] utilizing the MATPOWER software package,[21] a full AC and DC optimization framework developed at Cornell University, to solve the OPF problem. Like a RTO, MATPOWER solves the OPF problem by minimizing the cost of operating the electric power system subject to the demands and availability of electricity at each node, the transmission capability of each line in the system, and the voltage and stability requirements.

The standard formulation of MATPOWER's AC OPF problem solves for the endogenous variable x, for vectors of voltage angles Θ, voltage magnitudes V_m, real power injections P_g, and reactive power injections Q_g (Zimmerman, Murillo-Sanchez, and Thomas, forthcoming).[22]

$$x = \begin{bmatrix} \Theta \\ V_m \\ P_g \\ Q_g \end{bmatrix}$$

The standard MATPOWER formulation can be extended to include user-defined costs f_u and endogenous variables z. For the purposes of these simulations, additional costs are imposed in the objective function to include the cost of the pollutants in the model, CO_2, SO_2, and NO_x.

Therefore, the generalized formulation of the OPF problem takes the following form:

$$\begin{aligned} \min_{x,z} \quad & f(x) + f_u(x,z) \\ \ni \quad & g(x) = 0 \\ & h(x) \le 0 \\ & x_{\min} \le x \le x_{\max} \\ & l \le A \begin{bmatrix} x \\ z \end{bmatrix} \le u \\ & z_{\min} \le z \le z_{\max} \end{aligned}$$

It is assumed that in solving the OPF that the generators exist in a competitive market. The numerical simulations (and the theoretical model) do not attempt to analyze the potential for or impacts of exercising market power either in the electricity markets, cap and trade auctions for environmental allowances, or interactions between the two. Therefore, each generator is assumed to offer its entire range of real generation capacity at its (constant in these simulations) marginal cost.

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[19] See Appendix B for technical computation information and source code.
[20] See http://www.mathworks.com/products/matlab/ for more information.
[21] See http://www.pserc.cornell.edu/matpower/ for more information.
[22] The DC OPF problem only solves for Θ and P_g, not V_m or Q_g.

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